From:	East, Eric
To:	SPP Markets+
Subject:	**External Email** Markets+ Service Offering Comments
Date:	Friday, October 28, 2022 4:36:18 PM

Group –

Please find the comments below from Black Hills Corporation for: Black Hills Power, Black Hills Colorado Electric, and Cheyenne Light Fuel and Power.

- GHG Accounting
    - Black Hills strongly recommends separating the GHG requirements from the economic dispatch solution. Any GHG accounting or potential penalty collection and allocation should be limited to members that have those specific requirements and applied post-dispatch in the settlements process.

- Resource Adequacy
    - Black Hills' concern with exclusively utilizing WRAP would arise in the circumstance where the settlement and delivery provisions within WRAP cannot be reasonably met by some Markets+ members, particularly if the Markets+ footprint has areas that lack sufficient transmission connectivity, either physical or contractual. We support for the ability to self-supply reserves and certify.

Eric M. East | Manager, Tariff and Contract Administration
Black Hills Corporation | O: 605.721.2261| C: 605.484.8676

From:	Sanders, Steve
To:	SPP Markets+
Cc:	Sanders, Steve; Steven Johnson
Subject:	**External Email** WAPA comments on Markets+ Draft Service Offering
Date:	Sunday, October 30, 2022 8:24:51 PM

Greetings,

WAPA has reviewed the Markets+ Draft Serving Offering (DSO) document and submits the following comments:

1. WAPA is generally supportive of the comprehensive DSO, and the need to resolve a number of the outstanding complex issues (many of which SPP noted in the DSO such as market structure option) in the Phase 1 process. WAPA would appreciate SPP providing additional details and having further discussions related to the recommendations for market structure, congestion exposure and hedging, congestion rent distribution approach, and MTS provisions. WAPA appreciates that SPP has proposed to do just that in the DSO for many of these issues during the Phase 1 process. It is WAPA's expectation that additional examples will need to be developed by SPP to clarify and refine the congestion rent distribution proposal (for example) during Phase 1 to address outstanding questions for WAPA and likely others.
2. On Page 26 of the DSO, it notes "SPP will develop a more specific list of market participant opportunities and requirements in the next detailed design phase, but the guiding principle is entities can directly participate in Markets+ if willing and would not be required to participate through an intermediary." Does SPP also plan to further detail the complexities and proposed treatment of potential non-participating entities within the BAAs (if that is what "if willing" suggests) during Phase 1, both from a registration and transmission access perspective, to clarify the BA's and non-participating party's responsibilities?
3. On Page 36 of the DSO (Grouped Hydro Model), it states "As part of the next stage of detailed market design, SPP and stakeholders will determine if an existing resource participation model can adequately account for these operating characteristics or if a new hydro-specific model is necessary." It is unclear to WAPA what is intended here by SPP, as generally certain individual hydro units can be aggregated for market purposes and have been in other existing market constructs. Can SPP discuss and clarify this further in the updates to the DSO as that is a very important provision for entities with hydro resources?
4. WAPA supports the importance of resource adequacy, and further exploration of the proposed Resource Adequacy approach in the DSO in Phase 1, as some of the potential participants in Markets+ may already be in a different RA program than the WRAP, and it would therefore be important to ensure that the SPP proposal would be a workable concept.
5. As indicated previously in its comments on the MMU, WAPA is supportive of SPP's proposed MMU approach using the independent SPP MMU, which WAPA believes would provide an efficient, lowest cost market oversight. WAPA is also supportive of the Governance updates that SPP has proposed in the DSO based upon responding to numerous requests from the

stakeholders. It is WAPA's expectation that many of the remaining details/concerns related to the operation of the various Markets+ committees will be discussed and resolved during the Phase 1 process as the tariff language and potential rough charters related to those committees are drafted and reviewed.

6. WAPA is interested to hear SPP's proposed plans for Phase 1 participation (starting with the Nov 1st meeting), and what structure and options are proposed for interested parties to continue participation in the Phase 1 efforts given differing constraints such parties may have. Continuing broad involvement would be beneficial, as it is generally in the detailed development of the tariff and market protocols language phase that many of the remaining market provisions, unique requirements for certain parties, and issues get identified, resolved, and incorporated.

WAPA appreciates the opportunity to provide feedback. WAPA looks forward to continuing its involvement during the Phase 1 process. If you have any questions, please let me know.

Thanks..

Steve..

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Western Area Power Administration

October 29, 2022
Southwest Power Pool
MarketsPlus@spp.org

Re: Interwest Energy Alliance comments, Markets+ formation – draft service offering issued September 30, 2022 ("Markets+ Draft Service Offering")

Dear Markets+ formation team:

The Interwest Energy Alliance ("Inerwest") hereby submits these initial comments related to the Markets+ Draft Service Offering published on September 30, 2022 related to formation of Markets+. Interwest is a 501(c)(6) trade association of renewable energy developers and manufacturers working with nongovernmental environmental organizations to promote growth in the renewable energy markets throughout the Intermountain West, which includes Colorado, Wyoming, Utah, Nevada, Arizona and New Mexico. Several utilities in this region are actively engaged in discussions related to the development of Markets +, and Interwest members support the effort as a step towards the creation of a regional transmission organization which will bring efficiencies and savings, even greater than a day-ahead market can provide. Overall, Interwest recommends the parties working to create Markets+ establish a goal of moving to a regional transmission organization in the West, with as large a scope in services provided and load served as is feasible. A single transmission tariff and consolidated transmission planning and cost allocation will bring greater savings and is necessary to cost-effectively reach accelerated clean energy goals adopted by a number of Western states in a cost-effective manner. Interwest strongly supports a commitment to move towards balancing area consolidation with a single transmission tariff, and recommends that these steps be contemplated in future Markets+ organizer negotiations. Reducing pancaked transmission rates and wheeling costs with improved seams management remains a fundamental requirement for organized wholesale markets to provide the greatest long-term savings to consumers.

As found by the Colorado Public Utilities Commission ("CoPUC") a full-scale organized wholesale market and more expansive scope of services will bring greater benefits over a day-ahead market:[1]

> RTOs represent incremental potential benefits over and above EIM and DAM structures, though the exact level of incremental benefits depends on the level of services provided by each specific market. RTOs generally include regional transmission rate de-pancaking, regional transmission planning and cost allocation, allocation of interconnection access, management of market seams, governance structures, regional operating and planning reserve margins, etc.

Interwest looks forward to continued engagement as these discussions proceed.

DISCUSSION OF ISSUES

Interwest will comment on three primary issues in this document: A) the ability of individual generators to participate independently of host balancing area authority limitations, B) increased early attention to mitigating the restrictions and added costs from seams between Markets+ and adjacent systems; C) transparency of pricing in real time at pricing nodes, and D) continued attention to reducing barriers to stakeholder input and voting rights. Lack of reference to a particular discussion in the Markets+ Draft Service Offering should not be read to imply support; rather, Interwest may not have the specific expertise necessary to respond to some of the provisions and reserves comment to be submitted at a later date when the issues are more thoroughly fleshed out in the future. These initial comments are intended to highlight preliminary questions, especially about how Markets+ operations will affect independent power producers and renewable energy facility operations.

[1] CoPUC, *Colorado Transmission Coordination Act, Investigation of Wholesale Market Alternatives for the State of Colorado* (Dec. 1, 2021), Proceeding No. 19M-0495E ("Colorado Markets Report"), at 20.

(A) Enabling individual generators to fully participate will provide greater plant efficiencies.

Interwest's recommendations are designed to help Markets+ tap into all potentially available savings and emissions reductions available from diverse generation resources within its region. There are several components from the overall cost savings to be brought by Markets+. Markets+ dispatch rules will take advantage of price signals and individual generators' economic incentives to more consistently prioritize the use of the least-cost generating options. Allowing all generators within the balancing area to participate fully and to control their responses to market signals will incentivize them to take every feasible action to achieve savings. Savings come about through reductions in self-scheduled generation, scheduled maintenance, and unscheduled outages, overcoming transmission constraints within a balancing authority, elimination of the exertion of market power, and avoiding start-up costs.[2] Enabling all generators to fully participate in market sales opportunities can also help reduce curtailments of valuable renewable facilities, resulting in savings and reduced greenhouse gas emissions.[3] Increased revenue potential for individual renewable generation facilities will also likely increase their ability to obtain financing at lower costs. Western state commissions seeking efficient ways to meet clean energy goalswill be interested to see new renewable energy facilities rapidly deployed and fully utilized, with curtailments trending downward as the market increases their production relative to other existing fossil fuel driven resources over time.

[2] Cicala, at 9.
[3] *See* Steve Dahlke, *Effects of Wholesale Electricity Markets on Wind Generation in the Midwestern United States,* 122 ENERGY POLICY 358 (2018). This study reviewed performance in markets versus utility y dispatch by using a quasi-experimental framework based on observed outcomes.

To achieve these goals, Interwest requests that "Market Participants" be further defined to include independent power producers ("IPPs"), including those that are not a network resource. Interwest requests further clarity related to whether generators are required to have long term point to point transmission service or conditional firm service. By adopting the foregoing recommendations, Markets+ can provide plant-level efficiencies in addition to system-level efficiencies. Interwest also recommends careful attention to whether incremental costs will be imposed upon generators operating within Markets+ which have not executed a participation agreement to exercise transmission rights acquired through existing agreements.

To provide the full range of benefits Markets+ can offer, each generation operator must be allowed to fully participate on an individual basis through redispatch, rather than restricting full access to the market to operations controlled by balancing area authorities. Markets+ would be optimized by increasing trade flows, meaning the quantified import and export of electricity between balancing authorities, as much as possible. Some developing markets[4] effectively inhibit this direct access of generators between balancing area authorities rather than enabling full participating on a generator-by-generator basis. These markets leave to individual host balancing authorities the discretion to restrict generators within their balancing authority to the generator's good-faith forecast. These restrictions have taken the form of good-faith forecast submission requirements or indications that optimizing behavior could be considered capacity withholding. This limitation potentially limits renewable energy from fully contributing to the overall energy mix, despite its lower cost and deliverability and contribution to reducing overall emissions.

[4] As an example, consider California ISO's Western Energy Imbalance Market ("WEIM").

Markets+ can avoid this deficiency by allowing direct participation by individual generators. Interwest recommends that Markets+ allow generators to provide a forecast at or below expected generation levels, allowing generators to optimize their deliveries in the day-ahead or real-time imbalance markets.

Also, generators should not be required to serve load in a host balancing authority in order to participate in Markets+ or an energy imbalance market. Requiring generators to serve load in the host balancing authority inhibits the lowest-cost resources from being dispatched to meet market-wide needs and potentially is in violation of Federal Energy Regulatory Commission ("FERC") policy requiring public utilities to allow for and assume that power flows into and out of balancing authorities.

B. Markets+ organizers should create seams mitigation strategies prior to filing for FERC approval, to be implemented upon commencing services.

Since Markets+ participants are not yet committed to consolidating balancing areas and formation of an organized wholesale market, Interwest appreciates the mention of seams and formation of the seams task force in the Markets+ Draft Service Offering.[5] Interwest recommends that the seams task force develop business practices early in the process of developing Markets+ so the day ahead market will begin operations as efficiently as possible. The tariff and these business practices could then be readily converted and adopted by RTO-West or other organized wholesale markets contemplated in the future across the Markets+ footprint. As stated in the CoPUC report to the Colorado legislature finding many potential benefits from Colorado utilities joining markets, most notably an Regional Transmission Organization ("RTO") or Independent

[5] Markets+ Draft Service Offering, pp. 63-64 (pdf. 65-66).

Service Organization ("ISO"), seams management remains a primary focus area to be confronted in advance of utilities entering a fully-developed RTO or ISO, including when the utilities join an energy imbalance market (or day ahead market).[6]

C. Publishing nodal prices in real time.

On a related subject, Interwest requests that Markets+ and the Western Energy Imbalance Service ("WEIS") post a website reflecting integrated real time nodal locational marginal pricing tied to mapping information commencing immediately upon its initial operation date, as Southwest Power Pool ("SPP") does for its market operations.[7] This transparency is necessary for efficient operations. As an example, CAISO posts real-time and historical pricing information on a nodal basis for its own footprint as well as for the WEIM.[8] While SPP posts a price contour map with settlement locations and binding locations, it should post a map with nodal pricing information like CAISO does. Doing so would eliminate one perceived advantage that WEIM has over WEIS or Markets+ and would allow stakeholders within SPP to benefit from additional transparency.

D. Continue to reduce barriers for stakeholder input and voting rights.

Finally, Interwest joins other stakeholders in support of the Markets+ proposal to lower hurdles facing a diverse set of stakeholder committee participation and encourages that barriers remain low for participants including states commissions and energy offices, environmental advocates specializing in energy issues, power marketers, and independent power producers. Interwest will continue to recommend that the annual fees be waived for non-profit non-governmental organizations and consumer advocates who participate in stakeholder processes and

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[6] Colorado Markets Report, *supra*, fn. 1, at 9.
[7] *See* Price Contour map, https://pricecontourmap.spp.org/pricecontourmap/.
[8] https://www.caiso.com/todaysoutlook/Pages/prices.html

desire to become members with voting rights. Discussion and vetting of issues with orderly and transparent voting by a diverse set of stakeholders acting in the public interest is central to regional market development and will be required by the Colorado regulatory commission and other state agencies to implement clean energy and other public policy goals.

Interwest supports very limited application of rules allowing use of closed and executive sessions, recommending they be restricted to matters of legal sensitivity, personnel matters, similar to the requirements under open records and open meetings acts applicable to state government agencies around the West.

The Markets+ Draft Service Offering reflects significant progress towards these goals and Interwest recommends the organizers continue to be responsive to state agency input in this regard. Interwest appreciates the stakeholder process and response on these important issues, and generally supports the Markets+ governance to date, so long as the access and voting rights for diverse types of stakeholders including environmental organizations and IPPs is preserved, and states continue to have significant influence on resource planning issues.

Thank you for the opportunity to submit these comments.

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Comments on the SPP Markets+ Draft Service Offering Proposal

Introduction

TransAlta Energy Marketing U.S. (TEMUS) appreciates the opportunity to provide comments on the Markets+ Draft Service Offering document released on September 30, 2022. The additional detail in the document allows for a better understanding of the overall framework proposed, and more importantly, how existing Open Access Transmission Tariff (OATT)-based transmission service will be impacted if the program is enacted as it is designed today.

About TransAlta

TransAlta Corp. is an Independent Power Producer (IPP), generation developer and wholesale energy marketer with operations in Canada, the United States, and Australia. In the western US TransAlta owns and operates the 670 MW Centralia generation facility, the 68 MW Skookumchuck wind and hydro complex, the 140 MW Wyoming Wind plant, as well as a portfolio of projects in development. TEMUS is very active in the western wholesale power markets for both the medium-term and short-terms, and on both an asset and proprietary basis.

Comments

TEMUS supports a number of core elements in the Markets+ design, including:

- Direct transfer revenue settlement between the transmission customer and the Balancing Area Authorities (BAAs);
- Allocation of congestion revenue in proportion with Transmission Service Rights (TSR);
- Zonal Greenhouse Gas (GHG);
- Convergence bidding.

TEMUS recognizes that the success of the Western Energy Imbalance Services (WEIS) and recent Federal Energy Regulatory Commission (FERC) tariff filing of the Western Resource Adequacy Program (WRAP) has created a window for greater efficiency and reliability between the various regional BAAs, spurring the development of the Markets+ initiative. However, TEMUS has significant concerns with several pillars of the design, chiefly the inability for most market participants to choose to join Markets+, and the removal of the ability of transmission rights holders to exercise those rights after the close of the Day-Ahead Market (DAMKT). TEMUS further outlines these concerns below.

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Participation & Governance

The proposed participation model grants the BAAs the choice to continue operating its markets as it does today or join Markets+. All other Market Participants (MPs) are held captive to that choice. This lack of choice is critical because Markets+ would dramatically alter how transmission customers are able to exercise their scheduling rights – those entities inside the Markets+ footprint would be subject to potential redispatch costs if they exercise their rights after the close of day-ahead (DA), which is common practice today. Their "choice" to officially join Markets+ determines only if they may receive congestion revenue and be granted voting rights.

This approach is fundamentally different from that incorporated in WEIS where ALL market participants are afforded the choice to join. Given the way that the participation model and the optimization of transmission rights interact, it is very concerning that not all market participants are afforded voting rights once their BAA joins Markets+.

> **TEMUS recommends that the participation model include the ability for transmission customers such as TEMUS to "opt out" of Markets+ so that they may continue to transact and schedule as they do today without re-dispatch or uplift charges. This would extend the "voluntary" nature of the program to all customers, not only BAAs.**

Transmission Service Rights

The Markets+ "all in" transmission market design, where any transmission rights not scheduled DA are automatically utilized by Markets+, is an unjust taking of contract-path OATT service. TEMUS understands that a day-ahead market relies on abundant transmission to operate at maximum efficiency, but this goal cannot be achieved at the cost of transmission customers, whose rights to exercise their scheduling rights in real-time (RT) <u>at no additional cost</u> are being taken by Markets+.

There are three reasons to leave RT scheduling rights undisturbed is imperative. First, contract path OATT-based service allows transmission customers to exercise their scheduling rights up to the WECC deadline of twenty minutes before the hour (xx:20).

Second, there is significant value in the option to schedule firm transmission between DA and RT, and the value of this optionality is factored into the valuation of the rights purchase. Markets+ current design would unfairly alter these rights after DA regardless of whether the transmission contract holder has chosen to join Markets+.

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Third, the electricity market is inherently uncertain. There are many reasons why a transmission customer may have to adjust its DA plan and schedule in RT for reasons beyond their control, such as severe weather and unplanned outages. However, the Markets+ framework does not recognize such instances, and any deviations between day-ahead and real-time penalizes transmission customers for exercising their rights in RT by exposing them subject to settlements for those deviations.

TEMUS recommends Markets+ choose one of two solutions:

1. **Leave transmission customers harmless by not applying uplift charges when their transmission rights are exercised in RT, or;**
2. **Allow transmission customers to opt their contracted capacity out of Markets+ use.**

Further, TEMUS also recommends that Markets+ should ensure that scheduling priority be unaffected when a transmission customers chooses to opt-out.

In addition, TEMUS would appreciate additional clarity on the following:

1. Examples of how the Markets+ optimization prioritizes scheduling:
    a. For non-participating schedules;
    b. WRAP schedules;
    c. Self and base schedules;
    d. RT redispatch;
    e. Short-term and non-firm TSRs;
    f. BPA re-direct and resales.
2. How would scheduling priority change and/or flow constraints bind under scarcity conditions?
3. The September 30th draft mentions that the market design minimizes the incentive to self-schedule and includes a recommendation from the Market Monitor that self-scheduling be minimized. Please clarify if, and how, self-schedules and base schedules will be accommodated.
4. TEMUS supports the proposed allocation of congestion rent directly to transmission customers. However, clarification regarding how Markets+ would impact the allocation of congestion revenue in RT is needed.

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Market Transmission Service Rates

The September 30th draft document proposes to recover Market Transmission Service (MTS) costs from all energy and load cleared in the real-time market. However, allocation of these costs to supply-side resources creates inherent uncertainty for supply-side resource which will likely need to seek to recover these costs through energy bids, which is ultimately borne by load. It would be more straightforward and efficient to recover the costs directly from load.

TEMUS recommends that MTS costs be recovered from load to increase price transparency and market efficiency.

Rate Pancaking

One of the benefits of a Regional Transmission Organization (RTO) is the elimination of rate "pancaking", however, Markets+ appears to do so for internal transfers only and not for imports or wheels.

TEMUS would appreciate additional clarity on the following:

1. Please confirm if rate pancaking is eliminated only for internal Markets+ transfers only;
2. Please explain if wheel-troughs would be subject to rate pancaking;
    a. If so, how would these transactions be settled?

GHG Accounting

In general, TEMUS supports the zonal approach towards GHG costs because it can provide greater price transparency, resulting in greater market efficiency. In addition, a simple approach should be pursued since several studies only find a marginal reduction in CO_2 emissions from RTO formation due to existing carbon policies.

TEMUS recommends that GHG costs/adders be separated from energy bids and the Local Marginal Price (LMP) to better preserve price transparency.

The design suggests that imports will submit a separate GHG adder. Please explain:

1. Whether internal resources would include GHG costs in their bids;
2. How the incentive for "resource shuffling" might be mitigated.

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Resource Adequacy

TEMUS applauds the work of SPP and western stakeholder in the milestone achievement of filing the WRAP tariff with FERC. TEMUS notes that the design of WRAP is underpinned by the ability of the bilateral market to manage short-term reliability challenges. As explained in the "Transmission" section above, the co-opting of transmission from rights holders in the Markets+ design undermines the ability of the bilateral market to respond to changing conditions. While TEMUS can appreciate that the Markets+ proposal seeks to approximate the operational benefits of a full RTO, this design element jeopardizes the goal of resource adequacy that the program was initiated to achieved.

TEMUS would appreciate additional clarity on the following:

1. Would market advisories be made available to all stakeholders (i.e., not only BAAs), and if so, are they made available to all stakeholders at the same time?
2. How scheduling priority, price formation, and intertie transfers and wheels would change under:
    a. Conditions of scarcity, and;
    b. Over-generation (i.e., negative prices).

Conclusion

There can be significant cost savings resulting from the formation of RTOs, including reduction in total energy production costs and in the total capacity investment necessary to maintain resource adequacy. SPP's WEIS has helped to realize part of these potential benefits through transmission coordination and the standing of unified RT energy market, and now WRAP will support a more integrated regional resource adequacy outlook. TEMUS recognizes that the Markets+ initiative was launched to help realize some of the remaining benefits that an RTO could provide – a unified DA energy market.

However, the changes proposed in the Markets+ design represent a significant step away from the way that energy markets transact and operate today and propose more fundamental changes than WEIS and WRAP. While TEMUS recognizes that the goal of Markets+ is to achieve the highest level of operational coordination**, the transmission commitment framework proposed simply subsumes existing transmission rights without compensation or replacement** – in a full RTO presumably these would be converted into financial rights.

TEMUS recommends that the transmission commitment framework be considered holistically, including its implications for transmission purchases (both short-term and

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long-term) outside of the Markets+ framework, as those purchases will have important implications for the incentives to join Markets+ and for how much transmission revenue may need to be collected to supplant lost sales. TEMUS urges SPP to work with stakeholders to seek to develop a solution, which may include a make-whole payment to transmission customers who elect to exercise their transmission rights in real-time, allowing rights holders to "opt-out" of provisioning their transmission to EDAM, or some other creative solution.

TEMUS appreciates the consideration of the comments provided and looks forward to continued collaboration on the Markets+ design.

WRA Comments on Markets+ Draft Service Offering: Greenhouse Gas Design

October 28, 2022

Markets+ Design Purpose

Western Resource Advocates (WRA) appreciates SPP's latest version of the greenhouse gas design for Markets+. WRA recognizes that the Markets+ greenhouse gas design is intended to incorporate least cost optimization to serve load in states with carbon pricing with a proposed zonal approach. Since Markets+ is a new day-ahead market service effort, WRA is interested in ensuring the Markets+ greenhouse gas proposal thoroughly addresses pricing, optimization, reporting, and settlement to capture environmental externalities. Given the critical nature of successful greenhouse gas design, WRA urges deeper development, explanation, and education on the modeling of the zonal approach and consequent needs for compliance with western state policies. SPP should provide a timeline and scope of continued stakeholder engagement on greenhouse gas design and the release of a more substantive written proposal.

Tracking and Reporting, Needs for Western States

WRA views the establishment of a singular comprehensive tracking mechanism for greenhouse gas emissions and zero-emissions generation in the Western Interconnection to be essential to robust and transparent wholesale energy market development. We also recognize that SPP is not the only market operator in Western Interconnection with a day-ahead market service offering. Therefore, consistent reporting of greenhouse gas emissions by all market operators is vital and a fundamental part of the market function involving settlement and market performance. Since some states have emissions reduction or clean energy policies that do not include a carbon price, such a mechanism will assist states in ensuring compliance. Additionally, since some utilities operate across multi-state footprints, this mechanism will also support the ability to evaluate adjacent state emissions. We appreciate SPP's anticipation of "the need for the market operator to support tracking and reporting the production of generation by fuel type in its footprint beyond what's necessary for the GHG zones with pricing requirement." **In response, WRA recommends that SPP work with the Western Renewable Energy Generation Information System (WREGIS) to develop a comprehensive all-generation tracking mechanism for the Western Interconnection. The Markets+ greenhouse gas design should also be flexible for coordinating in the future with other markets, to address accounting under seams scenarios.**

As noted in the draft service offering, it's essential that the greenhouse gas design "implements a solution that meets the intent of western states' GHG policies." WRA therefore recommends further discussion of the needs of states with greenhouse gas reduction policies, but without emissions pricing, in Markets+ greenhouse gas design within the market and reporting post-market. WRA requests SPP provide a timeline and scope of continuing stakeholder engagement on this market design element.

Greenhouse Gas Pricing and Dispatch

WRA supports further development of the proposed zonal approach, as it appears well-suited to price environmental externalities and limit compliance leakage that may occur when greenhouse gas-emitting generating resources are shifted to a new jurisdiction, rather than reduced overall. The zonal approach also reflects the geographic diversity of future Markets+ participants, as necessary for maximizing the benefits of expanded access to clean energy resources across the Markets+ footprint. However, the current proposal in the draft service offering is insufficient to accurately assess the feasibility of the design and viability of implementation.

For example, one key area of continued discussion is setting a greenhouse gas emissions rate. WRA supports further exploration of establishing a greenhouse gas rate by multiplying an emissions rate by an allowance price. However, there are multiple methods to determine an emissions rate and identifying the "ideal" greenhouse gas rate will take multiple iterations of different price setting. We recommend SPP identify how this identification will proceed.

Given that Markets+ is a new design effort and the proposed zonal approach is a solution yet to be operationalized and tested, WRA recommends SPP further develop the specifics of greenhouse gas price formation, optimization, accounting and reporting, and settlement in tandem with each other and the market design as a whole. WRA requests additional attention given to the zonal approach to ensure the locational marginal price reflects the externality costs. Process wise, WRA recommends that SPP invest in further technical workshops for all stakeholders on greenhouse gas accounting and in modeling the proposed greenhouse gas solutions. It is in SPP's interests to model the different ways in which greenhouse gas accounting is possible and can comply with not only carbon pricing programs, but also other emissions reduction or clean energy policies. WRA has proposed best practices to be considered by any market operator as part of GHG accounting and reporting, in any market construct. We petition SPP to consider any or all of those recommendations in the design of the Markets+ GHG business practices protocol. Further discussion and formation of a more substantive proposal is essential to accurately assess the feasibility of the greenhouse gas design to operate in Markets+.

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Joint Comments on SPP Markets+ Draft Service Offering (Sept. 30, 2022)

Governance and Market Monitoring Sections

October 28, 2022

Submitted via email to marketsplus@spp.org.

Western Resource Advocates (WRA) and the Sustainable FERC Project (S-FERC), the "Joint Commenters," appreciate the opportunity to provide comments to the Southwest Power Pool (SPP) on the Governance and Market Monitoring Sections of SPP's Markets+ Draft Service Offering, published September 30, 2022 ("**Draft SO**").[1]

Governance

Our comments continue to be guided by the following good governance principles:

- Independent Board
- Transparency
- Meaningful, effective and diverse stakeholder engagement
- Significant role for commissioners and others who represent the public interest.

We view these principles as consistent with the Multi-state Electric Organization Principles and FERC's stakeholder involvement policy which is included in FERC Order 719.[2] We also apply the principle of "adaptability"[3] to guide our comments. Given the consequential shifts in the electricity industry in the last decade, it is likely the future of the electricity industry will continue to be very different. The governance design should provide stability but also reflect the need and ability to adapt to changes in the industry as well as changes in state policy.

The Joint Commenters appreciate that SPP made a number of changes that are meant to address some of the recommendations made by public interest organizations (PIOs) and other Western stakeholders in the last round of written comments and during other opportunities for public comment since release of the Draft Governance Straw Proposal version 2.0. For example, the Governance Section of the Draft SO includes a waiver of the membership fee for eligible

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[1] The Governance Section of the Draft SO is the Markets+ Draft Governance Straw Proposal, version 3.0, published September 27, 2022, available at: https://www.spp.org/documents/67948/09272022%20version%203.0%20final%20clean.pdf. The Draft SO, "*A Proposal for Southwest Power Pool's Western Day-Ahead Market and Related Services,*" is available at: https://www.spp.org/documents/67974/draft%20service%20offering%20proposal.pdf, ("Draft SO").

[2] Multi-state Electric Organization Governance Principles (April 14, 2022) (endorsed by the following states: AZ, CA, CO, ID, MT, NV, NM, OR, WA, and WY) available at: https://www.westernenergyboard.org/wp-content/uploads/Multistate-Governance-Principles-4-25-22.pdf ("State Endorsed Governance Principles"); Federal Energy Regulatory Commission, Order No. 719: *Wholesale Competition in Regions with Organized Electric Markets*, Docket Nos. RM07-19-000 and AD07-7-000, Oct. 17, 2008, available at: https://www.ferc.gov/media/order-no-719 ("FERC Order 719").

[3] See, e.g., Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 Cal. L. Rev. (February 2021) available at: https://www.californialawreview.org/print/rethinking-grid-governance/; Energy Freedom Colorado, Comments on Wholesale Market Options for Colorado Utilities, Colorado PUC Docket no. 161-08-16E (April 2, 2018) §3, available at: https://energyfreedomco.org/puc-mwtg-efco-comment5.php.

nonprofits (PIOs and others recommended the elimination of the fee); provides a clear and largely consistent standard for meeting closures;[4] and offers *the potential* for broader stakeholder engagement on committees, working groups and task forces (broader than participants that contribute generation or load to the Markets+ market or that pay a $5,000 annual fee). These are significant improvements on SPP's prior proposal (Markets+ Governance Draft Straw Proposal version 2.0).[5] However, overall, the Governance Section of the Draft SO does not afford a sufficient and equitable opportunity for all stakeholder groups to engage in the stakeholder and decision-making processes, particularly PIOs and others that represent the public interest; includes provisions that weaken autonomy without a counterbalancing justification; and leaves important details unaddressed. Further, it appears that only entities that "commit a non-refundable amount" will participate in the next phase of the governance design (called "Phase 1" of the funded investigation in the Draft SO).[6] Important decisions will be made as the governance design moves from a proposal to more detailed tariff provisions for Federal Energy Regulatory Commission (FERC) consideration and organizational bylaws. Limiting participation in "Phase 1" is not consistent with the governance principles supported by the Joint Commenters, other PIOs, Western regulators and the Federal Energy Regulatory Commission (FERC).

We incorporate our previous comments herein and reference them rather than repeat them in this document.[7] Though not all of the recommendations from our prior comments are referenced in this set of comments, we continue to endorse those recommendations.

1. Member Dominated Structure

The following high-level criteria can be used as a useful tool for evaluating governance design: (1) diversity of access; and (2) decision-making influence. A governance design that includes a stakeholder process that is open equally to all rather than providing superior opportunities to market participants or a subset of stakeholders (diversity of access); and in which decisions are made by an independent body, as opposed to providing decision-making authority or greater influence to market participants or a subset of stakeholders (decision-making influence) is more consistent with the best practices supported by the Joint Commenters, other PIOs, Western regulators and the Federal Energy Regulatory Commission (FERC). Historically, Western stakeholders have favored this type of governance structure.[8]

Though the Governance Section of the Draft SO includes significant improvements to SPP's previous governance proposal, as a whole, the governance structure represented by the Draft SO would accurately be described as participant dominated. The stakeholder process provides superior opportunities to market participants and market participants have a dominant role and greater influence in decision-making than other stakeholder sectors.

[4] There is a question as to the usage of different verbs. This is discussed in Section of 6 of this document.
[5] Markets+ Draft Governance Straw Proposal, version 2.0 (revised June 24, 2022), available at: https://www.spp.org/documents/67356/06242022%20governance%20revised%20straw%20proposal%20clean%20final.pdf.
[6] Draft SO, §2.1.
[7] Combined comments of all stakeholders on SPP's Markets+ Draft Governance Straw Proposal version 2.0 (June 23, 2022) (Joint Comments of WRA and S-FERC at 80), available at: https://www.spp.org/documents/67572/revised%20governance%20straw%20proposal%20comments.pdf (hereinafter "Combined Comments on v. 2.0)".
[8] Two examples of this are the CAISO and the recently developed Western Resource Adequacy Program (WRAP).

Research suggests that participant dominated arrangements produce reforms that serve incumbents' business interests but struggle to effectuate reforms that enhance competition or shrink the demand for electricity. Structures in which industry members "vote" on the rules for regional electricity markets and grid operation, often serve as an impediment to progress on clean energy and energy conservation measures that lead to lower costs.[9] In addition, a more insular governance model with voting power vested largely in generation and transmission owners, as well as consensus-driven decision-making rather than more democratic across many stakeholder groups, would tend to favor maintenance of the status quo at a time when adaptability to a changing energy landscape is needed.[10]

The comments herein, and our prior comments on the Markets+ Governance Straw Proposal version 2.0, include recommendations for improving the Markets+ governance design to align more closely with the governance principles supported by the Joint Commenters, other PIOs, Western regulators and the Federal Energy Regulatory Commission (FERC).

2. Independent and Autonomous Markets+ Governing Body

An autonomous Markets+ independent board is a priority design goal for Western stakeholders. This encompasses FERC financial independence[11] as well as autonomy from SPP, Inc. and independence from the (profit driven) Market+ market participants. SPP has proposed that one of the five Markets+ Independent Panel (MIP) members will be an SPP, Inc. Board member. We appreciate that the SPP, Inc. Board member on the MIP will no longer automatically be the Chair of the MIP. Pursuant to §3.2.2 of the Draft SO, the MIP will choose its chair and we support this.

However, according to SPP, the purpose of including an SPP, Inc. Board member on the MIP is to provide connectivity and increased communication between Markets+ and SPP, Inc. No explanation has been provided for why a liaison position is not sufficient and there is precedent for using nonvoting liaisons. Liaison positions are used in the WEIS governance structure. Each state in which a WEIS market participant has either generation or load participating in the WEIS may appoint one commissioner to serve as a state liaison (with no voting rights) to the WEIS Western Markets Executive Committee (WMEC).[12] On the other hand, including an SPP Inc., Board member on the MIP with full voting rights diminishes the MIP's autonomy and opens the door for other difficulties. As pointed out by PGP: the SPP, Inc. MIP member could choose to block MIP decisions by effectively appealing any issue to the SPP, Inc. Board; the proposal inappropriately gives the SPP, Inc. Board MIP member "two bites at the apple" with the ability to vote on issues at the MIP and later make the final determination on the SPP, Inc. Board; and the SPP, Inc. Board MIP member may not be able to avoid conflicts (or the perception of conflicts) of their duty and obligations to the two governing bodies.[13]

In addition, we continue to recommend the changes to the nomination process and removal of MIP members included in our last set of comments. As proposed in the Governance Section of

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[9] Welton at 209, 212-214, 216. The author's conclusions are drawn from a review of dozens of clean-energy-related filings at FERC.
[10] *See*, Energy Freedom Colorado, §3.
[11] Federal Energy Regulatory Commission, Order No. 2000: *Regional Transmission Organizations*, Docket No. RM99-2-000 (Dec. 20, 1999).
[12] Program Overview: SPP's Western Energy Imbalance Service Market (WEIS), at 11 (v. 1.2.5 published July 1, 2020) available at: https://spp.org/documents/61320/weis%20program%20overview%201.2.6.pdf.
[13] Combined Comments on v.2.0 at 2-3 (PGP Comments).

the Draft SO, these provisions reduce the MIP's autonomy and introduce unnecessary inefficiencies without providing justification for doing so. In summary, our recommendations are as follows:

- Load and generation participants and fee payers should not have the authority to override and replace the Nominating Committee's role through a petition and vote. If a nomination is rejected, the Nominating Committee should reconvene and submit another nomination. After the first MIP is seated, SPP should consider having nominations approved by the independent MIP rather than by a vote of load and generation participants and fee payers.
- Eliminate the authority of load and generation participants and fee payers to remove independent MIP members by a petition and vote. Give the independent MIP members the authority to remove other MIP members for well-defined reasons.

3. Annual Fee ($5,000)

The $5,000 annual fee appeared for the first time in the SPP staff drafted Markets+ Governance Straw Proposal version 1.0 and it does not appear to enjoy wide support from Western stakeholders. According to SPP, the rationale for the fee is to address the "disingenuous stakeholder" problem --that is, avoid committee members who vote but do not take seriously their responsibilities to stay informed and participate in meetings constructively. However, as pointed out by a number of stakeholders, this can be addressed in a more targeted manner, for example, having sectors nominate representatives to serve on committees.

The addition of a waiver is an improvement; however, significant details are not included in the Draft SO. It states only as follows: "The annual fee *may* be waived for eligible entities that are non-profit organizations under the Internal Revenue Code."[14] (*Emphasis added*). Further, if this provision is not amended in the final SO, refinements to the waiver provision will be made in a closed process. It appears that only entities that *"commit a non-refundable amount"* will participate in the next phase of the governance design (called "Phase 1" of the funded investigation in the Draft SO). Ironically, those who may need a waiver to fully engage in the stakeholder process would not be able to take part in further developing the waiver provision.

We continue to support the elimination of a membership fee. In the alternative, the waiver provision should be as broad as possible, have minimal hurdles, be clear and objective (e.g., it should be an administrative process), and be offered on a continuous basis (i.e., the application period should not be limited to a certain window of time). Further, any proposal to eliminate or limit the waiver beyond its initial scope should be subject to an elevated standard, such as a super majority vote by the MIP.

4. Markets Plus Executive Committee (MPEC)

MPEC membership has been expanded from load and generation participants to also include members who pay a $5,000 annual fee or are granted a membership fee waiver.

The Joint Commenters support this provision with the following recommendations for consideration and with the addition of changes to the Market Working Group standing committee (MWG): First, pursuant to §3.3.1 of the Draft SO, the MPEC member "shall be a

[14] Draft SO, §1 definition of Markets+ Market Stakeholder (MMS).

senior level management employee with financial decision-making authority." This requirement makes sense for commercial participants; however, it needs to be refined to appropriately reflect the organizational structure and mission of PIOs. As it is written, it would be a significant hurdle for (and possibly bar) PIO participation on the MPEC. PIOs are not profit driven market participants. It would not be feasible to assign "senior level management with financial decision-making authority" to the MPEC. Further, PIO staff meeting that requirement would not be the appropriate MPEC member. Technical staff employed to engage and participate in western coordination efforts are better equipped to understand the issues and participate on the MPEC.

Second, without a more refined waiver provision, it is not clear PIOs would even qualify to serve on the MPEC.

Third, the voice of PIOs and other entities that are not investor owned utility or public power participants will be overwhelmed under the proposed voting structure. Pursuant to §3.3.1.4. of the Draft SO, there are three voting sectors: 1) investor owned utility participants; 2) public power participants; and 3) essentially everyone else. Each sector represents 1/3 of the vote and "an action is approved by the MPEC if the average of these percentages is at least 67%." Therefore, sectors 1 and 2 can approve actions with de minimis support from sector 3, a sector that will have very broad membership. This voting structure also applies when MPEC establishes standing working groups.[15] Ideally the voting structure would be altered to give more appropriate weight to entities that are not in sectors 1 and 2. However, at a minimum the Governance Section of the Draft SO should clearly articulate a process by which minority opinions would be provided to the MIP at the same time as the majority decision.

An alternative that has been under discussion, and supported by a number of stakeholders, is the inclusion of a second advisory body. It would be composed of PIOs and some of the other nonparticipant entities, and like the MPEC, it would provide only advisory opinions to the MIP. Advantages of this option include, but are not limited to, the following: the voice of nonparticipant entities would not be overwhelmed by participants; the advice and opinion of PIOs and other nonparticipant entities would be clearly articulated to the MIP; and this advisory body could focus on the issues most important to the mission of the members and falling within their expertise (i.e., the second advisory body may not choose to provide advice on all issues).

Finally, §3.4.1.5 of the Draft SO includes three additional standing committees (i.e., permanent working groups). One of the newly added permanent working groups is the MWG which will review "any initiative that would modify the Markets+ tariff or market protocols."[16] The Joint Commenters support further development of the MWG to more closely resemble the WRAP Program Review Committee (PRC).[17] For example, sector representation would be specified on the MWG and the sectors would self-select their MWG members. Further, the MWG's role and position in the decision-making process should be reviewed.

5. Participation on Working Groups and Task Forces

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[15] Draft SO, §3.4.1.

[16] Draft SO, §3.4.1.5.2.

[17] Western Resource Adequacy Program – Governance Proposal, at 26 (January 2022), available at: https://www.westernpowerpool.org/private-media/documents/2022-01-13_WRAP_Governance_Proposal_final.pdf.

Even with the waiver provision, which *allows* nonprofit stakeholders to participate on committees, working groups and task forces and vote in those groups, there is no guarantee PIOs will get the opportunity to participate on working groups and task forces (and vote in those groups). Nor does it ensure that working groups and task forces will have broad or balanced sector representation and provide PIOs and other entities that represent the public interest with the appropriate opportunities to influence the work. Representation on task forces and working groups is largely by appointment or recommendation of the MPEC Chair.[18] Further, guidance regarding sector representation on working groups and task forces is very nonspecific, "criteria and sector representation … will be determined in the group's scope."[19]

We recommend establishing guidelines for sector representation on working groups and task forces similar to, but not necessarily exactly like, those that apply to the MIP Nominating Committee.[20] We also recommend allowing sectors to self-nominate members to the working groups and task forces, rather than having the MPEC Chair decide this. In addition, to ensuring a more balanced and inclusive stakeholder process resulting in a better work product, this would also eliminate the need for an annual fee.

6. Standard for Closing or Limiting Attendance at Meetings

The Governance Section of the Draft SO provides one standard for closing or limiting attendance at meetings for all of the organizational bodies (i.e., MIP, MPEC, working groups and task forces): "Matters for consideration in closed or limited sessions are [should be] limited to personnel, legal and proprietary, confidential or security sensitive information." We generally applaud and support this amendment but ask for a clarification. In §3.2.4 (MIP) and §3.3.1.3 (MPEC) the phrase used is "are limited to." However, in §3.4.1.2 (working groups) and § 3.4.2.2 (ad hoc task forces) the phrase used is "should be limited to." It is not clear if the usage of different verbs was intentional. If so, we ask SPP to explain their intention by using "should be." If the usage was not intentional, we ask that the final service offering use the phrase "are limited to" throughout.

If and when Markets+ is implemented, we recommend developing a policy that further refines the standard.[21]

7. Unresolved Issues and the Stakeholder Process

Though SPP is calling the current proposal a Draft "Service Offering," important issues remain outstanding, for example: issues related to SPP, Inc.'s, oversight authority;[22] joint issues (market design proposals that impact both Markets+ and SPP, Inc.), both defining the scope of joint issues and articulating how they will be addressed; better defining the procedures for addressing disputes between the MIP and SPP, Inc. under different circumstances; and refinement of the waiver provision. These issues can have significant implications on governance and should be discussed and vetted in a public forum. SPP described the SO as a document detailed enough for potential participants to perform their own feasibility studies. The Joint Commenters do not

[18] Draft SO, §§3.4.1.1, 3.4.2.1.
[19] *Id.*
[20] Draft SO, §3.2.3.2.1
[21] *See e.g.,* California ISO, Open Meeting Policy, v.3.8 (Dec. 9, 2019), §10 available at: http://www.caiso.com/Documents/CaliforniaISOOpenMeetingPolicy.pdf .
[22] Combined Comments on v. 2.0 at 83-84 (Joint Comments of WRA and S-FERC).

agree that the Draft SO meets this definition and there is very little time to address the outstanding issues in this stage of the program development, i.e., the final SO is expected on November 18, 2022.

Generally, the process has been rushed. Basic procedures for stakeholder processes were not followed (not even those being proposed in the Draft SO) which has made it difficult for stakeholders to provide thoughtful comments and effectively engage in the process. For example, meeting materials, including key documents that were to be discussed, were not published prior to meetings and a key two day in-person meeting did not provide a virtual option and was not recorded. Meetings that are recorded are not posted on a publicly available webpage; stakeholders must be aware they are recorded and know who to contact to get a link.

SPP has repeatedly expressed concern about stakeholders being sufficiently engaged in order to warrant membership on committees and the right to vote. However, SPP has the responsibility to not only assist stakeholders in their efforts to be educated and informed, but also to encourage this. We continue to make the recommendations included in section D, Design Process, of our prior comments,[23] for example:

- Posting meeting notices and materials (including agendas) prior to meetings;
- Providing a sufficient period of time to develop comments on SPP's work products;
- Providing virtual access to all meeting;
- Recording all meetings and providing access to the recordings on a public website;
- Maintaining a well-organized and easy to use website;
- Providing a user-friendly application to submit and review stakeholder comments; and
- Including in written proposals summaries of stakeholder comments and the basis for the recommendations made in the proposals.[24]

To this end, the Joint Commenters also request that SPP provide a schematic that graphically illustrates the stakeholder and decision-making process in the final SO. It would show the flow of the decision-making process through all of the relevant organizational groups with enough information to understand how decisions are made and the role of stakeholders and the organizational groups in that process. It is difficult to clearly understand the stakeholder and decision-making process in the Markets+ Draft SO through only the narrative. In other forums, such as the Western Power Pool's WRAP, a schematic has proven to be a useful tool to better understand the stakeholder and decision-making process.[25]

8. Participation in "Phase 1" of the Funded Investigation

As stated above, there are significant issues that remain outstanding. If they are not addressed in the final SO, they will need to be addressed in what the Draft SO calls "Phase 1" of the funded investigation. It appears from the Draft SO Phase 1 will not be an open process. This is not consistent with the governance principles supported by the Joint Commenters, other PIOs,

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[23] Combined Comments on v. 2.0 at 90-91 (Joint Comments of WRA and S-FERC).

[24] These recommendations should not be viewed as burdensome or unreasonable. At least one market operator, the CASIO, takes these measures.

[25] *E.g.*, NWPP Resource Adequacy Program – Detailed Design, at 43-44 (July 2021) available at: https://www.westernpowerpool.org/private-media/documents/2021-08-30_NWPP_RA_2B_Design_v4_final.pdf.

Western regulators and the Federal Energy Regulatory Commission (FERC). We recommend that, at a minimum, SPP clearly state in the final SO who can participate in "Phase 1" and that "Phase 1" is conducted as an open stakeholder process.

Market Monitoring

Hybrid Structure and Transparent Decision-Making for Markets+

Joint Commenters appreciate the provided overview of the SPP MMU, including responsibilities and recent recommendations. Joint Commenters recommend a hybrid market monitoring structure for the first three years of Markets+. We also request SPP provide substantive and transparent explanation of the market monitoring structure and activities specific to Markets+.

Specific Recommendations: Since SPP is entering the Western Interconnection to offer a new market product that will require the trust and confidence of all stakeholders, we recommend a hybrid market monitoring model with specific operation and stakeholder engagement elements:

1. We recommend this for at least the initial three years of Markets+ operation to ensure the new market is functioning smoothly and transparently and shows benefits to participants and impacted ratepayers. Since Markets+ will be contractual for day-ahead only, it may require a different and unique market monitoring process or data needs in the West. This is different from the status-quo market monitoring service in SPP offerings.
2. A functional hybrid model includes a clear demarcation of the respective oversight and roles of the internal and external monitors. Joint Commenters also recommend SPP Markets+ invest in additional staff to ensure the hybridized market monitor has adequate resources to serve the fiduciary duties of the Markets+ product, not stretch the existing SPP MMU staff, and not obfuscate monitoring of the two market offerings, that are different in operational footprint and terms of service.
3. Joint Commenters further request that SPP explain the operating plan for the selected market monitoring structure for Markets+. This would enable transparency and foster stakeholder trust and understanding of SPP's proposed approach. SPP solicited Markets+ Market Monitor comments due July 15, 2022, and we reiterate our request to make these comments public.
4. Joint Commenters recommend SPP establish a clear process for continued stakeholder engagement on market monitor design elements.

In general, we request clarification or elaboration of any agreements reached among SPP, the SPP MMU, and or stakeholders on market monitoring that are not included in this proposal. Additionally, while Joint Commenters appreciate the described responsibilities of and recommendations by the MMU for existing SPP offerings, it is unclear what is uniquely proposed for the Markets+ initiative, a contractual day-ahead market with an independent process and governance structure.

Joint Commenters finally recommend that SPP and the SPP MMU facilitate workshops for potential market participants and stakeholders to better appreciate foundational issues in successful market monitor design. This includes:

- Analysis of the potential structures of the market monitor and the benefits and challenges of each model.

- For the hybrid model, discussions of the role of the external consultant, advisor, or coordination with the surveillance committee.

Mitigation

Joint Commenters agree with the necessity of market power mitigation to prevent market power concentration and abuse. The market monitor should measure the ability of suppliers to profitably raise the market price of energy over its marginal costs to mitigate horizontal and vertical market power and ensure no market participants or market structure issues are manipulating the market. Market power can create economic inefficiencies and deadweight loss, resulting in increased costs to ratepayers. Joint Commenters recommend the following:

1. Market power monitoring include a "pivotal supplier" test to determine if a unit is essential in serving load at a particular load level. Virtual bidding and congestion rights are also an area of particular need for monitoring for any potential risk of manipulation.
2. Market power monitoring include consistent and robust reporting of the Markets+ overall functions and performance, and the market monitor should have sufficient tools and authority to do so.

Strong communication and coordination between the market operator and state and federal regulators are also important in robustly mitigating market power.

Joint Commenters note the final paragraph on mitigation on page 77. We request clarity on the language around mitigation design and the suggested change for Markets+. We view any efforts to change or remove existing mitigation initiatives prior to actual operation of the Markets+ service offering as premature and lacking proof of merit. Joint Commenters request additional justification on this proposal and requests substantive explanation of the MMU recommendations for Markets+.

Reporting and Transparency

Joint Commenters appreciate the description of the SPP MMU's reporting process, as these reports are critical to evaluating and improving market performance. In Markets+, these reports will be essential to ensuring market transparency and gaining the trust of stakeholders in a new offering in the West. Joint Commenters recommend the following seven areas of performance metrics and reporting in Markets+ to maintain transparency:

1) Market efficiency metrics to identify inefficiencies such as uneconomic energy dispatch.
2) Market power measurements of the ability of suppliers to profitably raise the market price of energy over its marginal costs.
3) Transmission availability reporting to maintain visibility over the utilization of transmission infrastructure as pared to its operational limits, both physical and contractual.
4) Measures of greenhouse gas reductions to understand the effects of market structures on the electric grid's carbon intensity over time. This includes comprehensive reporting of emissions post-dispatch by generation type, technology,

time frame, geographic footprint, and any additional data available to support states' different compliance needs. For an example of comprehensive reporting, see slide #22 of Powerex and Public Generating Pool's April 20, 2022 presentation to the Markets+ greenhouse gas design team.
5) System adequacy and stability information of the Markets+ footprint signaling whether enough resources and capabilities are available to operate the grid in a safe, reliable, and continuous manner.
6) Clear identification and reporting of dispatch under grid-stressed conditions due to extreme weather events and post-dispatch event management procedures.
7) Tracking and assessment of interchange transfers associated with seams, as Markets+ interacts with other wholesale energy markets in the West.

Additionally, Joint Commenters recommend the following additional reporting for the market monitor to include as part of market performance:

1. Produce regular, periodic reports of market performance to the Independent Board of Markets+.
2. Produce scenario-based trending reports that capture market performance due to resource mix changes, generation fleet changes, or extreme weather events.
3. Provide quarterly updates and summary assessments with as much transparency as possible to all relevant Markets+ and stakeholder bodies.
4. Ensure that market monitor staff are available to the SPP Markets+ stakeholder committees to respond to any questions and concerns.
5. In times of extreme weather events, communicate in diverse ways to not just SPP Markets+ market participants, but to state regulators, impacted customers and ratepayers.

Conclusion

Ensuring the new Markets+ offering is functioning well and shows benefits to stakeholders necessitates a transparent, well-justified, and well-planned market monitoring structure. Joint Commenters recommend a hybrid market monitor for at least three years to maximize market trust and performance. We also urge SPP and the SPP MMU to engage with stakeholders to explain existing decisions on market monitoring in Markets+ and to further develop the market monitoring design.

Note of Reference

A number of the recommendations on market mitigation and reporting come from a 2021 report, "Best Practices for Transparency and Reporting in Organized Markets," prepared by Strategen on behalf of WRA. WRA submitted this report in full to SPP during the Markets+ Market Monitoring comment period.

We appreciate the opportunity to engage in the development of the Markets+ Governance and provide recommendations to SPP. We look forward to ongoing engagement with SPP and the Western stakeholders.

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Comments of Powerex Corp. on SPP Markets+ Draft Service Offering dated September 30, 2022
Submitted October 28, 2022

Powerex Corp. appreciates the opportunity to comment on SPP's Markets+ Draft Service Offering dated September 30, 2022 and looks forward to the next version, as well as Markets+ Phase One - Funded Investigation. Powerex believes the successful development of a well-governed and well-designed full day-ahead and real-time organized market is critically necessary for the western region to achieve its grid decarbonization goals, while delivering affordable electricity service for consumers and protecting reliability.

Powerex appreciates SPP's collaborative approach to working with stakeholders as well as SPP's significant efforts in developing the Markets+ Draft Service Offering. ***Powerex strongly supports its direction.***

Specific highlights of the Markets+ service include:

- A durable and inclusive governance framework, supported by a new Markets+ Independent Panel (MIP) as well as the SPP Independent Board;
- A common resource adequacy requirement that will fully leverage the Western Resource Adequacy Program (WRAP) and protect reliability, prevent leaning, and eliminate the need for, and costs of, a resource sufficiency test;
- A flow-based approach to transmission availability that will maximize the use of transmission within the market, while equitably allocating congestion revenue to OATT customers and minimizing impacts to third-party transmission revenue;
- An approach to GHG tracking that will accurately apply GHG emissions costs to energy generated in, or imported into, jurisdictions with GHG pricing programs; and
- Industry best practices in price formation, consistent with FERC policy, ensuring that market prices accurately reflect grid conditions.

Powerex is confident that Phase One - Funded Investigation will further expand upon these important elements. ***Accordingly, Powerex is committed to proceeding with funding its share of the next phase to develop protocols and tariff language.***

For Phase One to have the best starting point, Powerex offers the following suggestions for the next version of the Draft Service Offering.

Governance

In its July 15 comments, Powerex highlighted its strong support for the robust, inclusive and independent governance framework being proposed and appreciates some of the refinements SPP has since made in the most recent version to the governance model. In particular, Powerex supports the refinement that the Markets+ Independent Panel (MIP) will select its own Chair as well as the establishment of standing committees for Operations and Reliability, Market Design and Seams.

Powerex notes that numerous opinions have been submitted with respect to the voting structure of the Markets+ Participant Executive Committee (MPEC) and stakeholders agree that the voting structure must be representative of the footprint in a durable manner. The voting structure should balance input from all stakeholders and participants while achieving the over-arching goals of reliability, efficiency, and equitable market outcomes. In Powerex's view, the voting structure should be designed to achieve the following four objectives:

1. Entities with a direct interest in market outcomes (market participants) have a substantial decision-making role;
2. Stakeholders that are not market participants are also meaningfully included in decision-making;
3. Decisions generally reflect that a majority based on the number of participants and stakeholders support the decision; and
4. Decisions generally reflect that a majority based on size (measured by generation and load) support the decision.

While the currently proposed voting structure meets the first three of these objectives, it is not clear to Powerex that the fourth objective will always be met. Powerex therefore recommends further limited refinements to ensure decisions will reflect the perspective and interests of a majority of the footprint based on size, as this will provide a more durable approach for an evolving footprint for years to come. There are several ways this could be addressed, including:

1. The Investor-Owned Utility (IOU) and/or Public Power sectors could allocate their votes within the sector based on each entity's total load and generation instead of being allocated per participant.
2. The IOU and/or Public Power sectors could allocate their votes per entity within the sector but apply an additional over-riding limitation that each region (defined as Northwest, Southwest and/or international), must be allocated a defined percentage of the vote within the sector.

Powerex recommends further discussion on this at the next stakeholder meeting.

In addition, further consideration of uniquely situated Markets+ Participants may be required for circumstances where the entity does not clearly fit clearly into one (or only one) sector. Specifically, it is not clear which category Powerex would fit into best. Powerex notes the Western Resources Adequacy Program (WRAP) includes Powerex in the IOU sector as an international entity. Powerex seeks further discussion with SPP and stakeholders on this topic.

Finally, the Operations and Reliability standing committee is defined to be comprised of participants that are a balancing authority or transmission provider. This should be extended to an affiliate of a balancing authority or transmission provider (in circumstances where that balancing authority or transmission provider is not otherwise on the committee). In addition, any concerns raised by the Operations and Reliability standing committee on proposals that are ultimately approved by the MPEC should be communicated to the MIP as part of the proposal.

To be clear, while Powerex recommends the additional limited refinements as discussed above to address these narrow issues, Powerex generally supports the proposed three-sector voting approach, particularly in the context of the overall governance proposal which includes the following key elements:

- Independence of the SPP Board;
- Independence and high level of authority of the MIP;
- Expertise and neutral facilitation role of SPP staff;
- Inclusivity of Markets Participants and other stakeholders in decision making through the MPEC; and
- New standing committees for Operations and Reliability, Market Design and Seams.

These elements offer the west a robust and durable governance framework. Powerex appreciates how the proposed framework accomplishes a durable governance solution with significant deference to the MIP's decision-making authority, as informed by inclusive stakeholder input, with impartial facilitation and expertise provided by SPP staff.

Market Monitoring

Market monitoring is important in any market, but especially so in a new market when market monitors may have perspectives that help shape the market design. Given this importance, Powerex believes the market monitoring model should use a hybrid approach, at least for the first three years. The hybrid model would rely on the expertise of both the SPP internal Market Monitoring Unit and an external Market Monitor (that would be selected based on which interested entity has the strongest capability, diversity and depth of experience and philosophical alignment with the Markets+ market design). The hybrid model will ensure that Markets+ receives the input from two market monitoring entities that collectively with provide exceptional diversity in perspective and knowledge of monitoring issues that have arisen in other organized markets. This particularly important in the formative years and considering that Markets+ (and any organized market platform) represents a fundamental change from the west's existing bilateral transacting structure. The total cost of having two market monitoring entities involved in the formative years will be relatively small in comparison to the significant volume of trade that will occur through Markets+, and the importance of getting the market design right. The market monitoring model could be assessed and modified after the fourth year (or perhaps after the first full year of operations) if needed. The hybrid model will also provide an excellent opportunity to evaluate which specific market monitor (whether internal or external) is the best fit with the Markets+ design and footprint, and allows for a much easier adjustment to an internal or external market monitoring model, than the other way around (i.e., starting with a selected internal or external market monitoring and then changing the entity or the model later).

Powerex believes the market monitoring model should use a hybrid approach in the beginning as the best approach for Markets+.

Market Power Mitigation

Powerex fully supports an appropriate market power mitigation framework that enables competitive outcomes by applying mitigation when necessary to protect against the material exercise of market power. Powerex believes there are two related topics to develop a workable framework and detailed approach for market power mitigation.

- *The most appropriate framework for the Markets+ footprint is Conduct and Impact*

A Conduct and Impact approach only applies mitigation if a participant's bid price exceeds a defined threshold above its reference price/default bid and if it also produces a measurable and material impact on competitive market prices. This approach — with the right parameters — is likely to be the preferred approach for most entities, but particularly those with energy limited resources, including entities with complex storage hydro systems that must maintain the flexibility to determine how to operate their facilities in light of numerous subjective (and often rapidly evolving) assumptions regarding current and future market conditions, availability of water supply, expected local demand, environmental restrictions, and recreational requirements. Similarly, many entities in the Southwest must navigate pipeline constraints and other fuel supply challenges for their gas resources, further emphasizing the need for market participants to have the ability to determine how best to deploy their resources (and at what price).

- *An acceptable approach to calculate reference prices / default energy bids must be developed for energy-limited resources*

A Conduct and Impact framework can help to ensure that market power mitigation procedures are not excessively triggered by first validating that a material risk of the exercise of market power exists. When mitigation is triggered, however, it also must be recognized that there is no calculation or formula that can accurately estimate the actual costs, including opportunity costs, of energy-limited resources like storage hydro. It is therefore critical to ensure that reference levels for mitigation do not result in a risk that participants with limited energy supply are mitigated to levels below their costs and forced to sell their limited energy supply at the wrong time. Powerex believes that SPP should review the formulaic approach to a Default Energy Bid that was developed for the Western EIM as a starting point for developing a workable reference level for hydro resources (and potentially other energy-limited technologies).

In summary, Powerex believes that a Conduct and Impact framework, combined with a reference level approach for energy-limited resources that is similar to the default energy bid approach developed for CAISO's EIM, will provide a workable market power mitigation approach for Markets+.

Resource Adequacy for Markets+

Powerex believes that a common resource adequacy requirement is a necessary foundation for developing a reliable, efficient and equitable regional organized market in the West. The experience of the CAISO's Western EIM over the past several years has demonstrated that applying a last-minute day-ahead or hour-ahead resource sufficiency test (instead of a common resource adequacy requirement) simply cannot resolve the negative consequences to reliability and inequitable outcomes that arise when one or more market participants perpetually enters the operational timeframe with a large capacity deficit. Resource sufficiency can only be reliably and equitably achieved by requiring all participants to take the necessary build and/or procurement steps well ahead of the operating time horizon. This necessitates a common resource adequacy requirement applied across the market footprint.

Powerex believes SPP's Markets+ proposal —a common resource adequacy requirement for Markets+ participants, with metrics defined by WRAP, combined with a must offer quantity based on the WRAP holdback calculations— is a far superior approach to a daily/hourly resource sufficiency approach, and a natural fit that leverages the momentum of the WRAP program throughout the west. A common resource adequacy requirement based on WRAP will ensure that each entity arranges, in advance, its equitable share of the aggregate capacity needed to maintain reliability of the market footprint. A must-offer obligation based on the WRAP holdback calculation will also ensure that the appropriate quantity of that resource adequacy capacity is made available to Markets+, providing participants and the market operator with full confidence that the market commitment and dispatch processes can deploy those resources efficiently in the operating timeframe while maintaining reliability.

Importantly, incorporating the WRAP holdback calculations into the determination of each entity's must offer quantity will also ensure participants are able to fully realize their WRAP diversity benefits as the quantity of their must offer requirement will be dynamically adjusted up or down to reflect potential holdback obligations or potential holdback requests from other participants. This ensures that WRAP members that pass the forward showing requirement can be confident that they will not face additional costs of "topping up" their resource adequacy supply to meet a daily resource sufficiency requirement when facing challenging conditions in their area (e.g., high load, forced outages, low VER output).

Powerex believes this framework will provide many opportunities for complementary synergies between WRAP and Markets+. For example, Markets+ can improve on the reliability and diversity benefits of the WRAP program by providing a market dispatch that will continuously deploy the WRAP supply of Markets+ participant to meet Markets+ load and committed exports throughout real-time. Powerex envisions that the WRAP/Markets+ framework could even largely replace the use of the WRAP operational program for Markets+ participants, as participants in Markets+ would no longer need to request holdback (and bear the associated costs) and could instead simply use Markets+ to make purchases of energy only in the hours it is needed.

In summary, the Markets+ proposal to implement a common resource adequacy requirement and associated must offer quantity obligation based on WRAP will enhance reliability, reduce costs, and ensure equitable outcomes and is far superior to a day-ahead/real-time resource sufficiency requirement.

Market Design

A key source of benefits from implementing a regional day-ahead market is the efficiency gains of a centralized unit commitment and energy dispatch across a broad geographic footprint. As described above, the foundation for achieving these benefits is a common resource adequacy requirement that ensures enough resources will be made available to the market. Also critically important, however, is developing an appropriate optimization approach to ensure that the market effectively *uses* those resources to produce an efficient and robust physical market solution that supports each BAA's continued responsibility to maintain reliability in their areas.

A successful market design must provide participants with confidence that Markets+ will commit the right amount of resources to maintain reliability and that individual BAAs will be able to count on market transfers to meet their load. Furthermore, Markets+ must make its commitment and dispatch decisions in a manner that efficiently deploys resources based on their capabilities, minimizes total production costs, and produces accurate prices that reflect system conditions. Powerex believes that the Markets+ proposal addresses these objectives, through three key areas:

Simultaneous co-optimization of all market requirements: Powerex supports SPP's proposal to develop enhancements to its standard market design to combine the financial day-ahead market and subsequent day-ahead residual unit commitment (RUC) process into a single co-optimization of energy, physical capacity and flexible capacity to commit sufficient physical resources to maintain reliability, while producing more transparent market prices and compensation that fairly reflects the needs of the grid. Powerex believes this is particularly necessary to minimize out-of-market unit commitment costs and uplift charges that are likely to be difficult to allocate fairly across a diverse footprint that will include many BAAs with predominately hydro resources (that do not face commitment costs today). Powerex proposes that SPP dedicate sufficient time in the next phase to review the approaches being considered in other markets (e.g., ISO-NE) in order to develop a more detailed proposal to achieve these objectives.

Flexible Reserves: Powerex supports a day-ahead and real-time flexible reserve product to secure the flexibility capacity necessary to ensure that the resource fleet is positioned to accommodate actual real-time conditions that may differ from day-ahead expectations. These products are another important element of a market design that is designed to efficiently secure sufficient physical resources to maintain reliability, while producing accurate market prices and avoiding out-of-market actions.

Price Formation: Powerex fully supports SPP's objectives of ensuring that prices in Markets+ will accurately reflect system conditions and provide appropriate short-term performance incentives and long-term investment signals. These objectives support achieving aggregate benefits associated with improved reliability and efficiency, and market outcomes that reflect environmental policy objectives. At the same time, accurate prices are crucial to enable the broadest group of individual participants, BAAs, and sub regions to benefit from participating in a regional organized market and to avoid inappropriate shifts of value from one group of ratepayers to another.

Powerex strongly supports the use of industry standard Fast Start Pricing logic as generally applied in SPP, PJM and NYISO. Fast Start Pricing is necessary to ensure that the costs of gas peakers are properly included in market prices and looks forward to discussion of the specific parameters best suited to Markets+.

Powerex also supports graduated Scarcity Pricing using a sloped demand curve that will allow prices to begin to rise in response to tightening system conditions and send appropriate price signals to encourage resource availability and performance (and demand reductions when possible). Further discussion will be required to determine which product(s) should include a demand curve and the specific price levels that should be applied.

In summary, the proposed Markets+ co-optimization of unit commitment and dispatch, and the proposed Markets+ price formation practices reflect industry best practices and can be expected to drive reliable, efficient and equitable market outcomes, with further details to be worked through in the next phase.

Transmission Approach

Developing an approach for transmission has historically been one of the most difficult challenges of expanding organized markets in the west. All stakeholders will agree that the best outcome for any regional market is to achieve maximum transmission availability with minimal hurdle rates. But gaining consensus and support requires more than demonstrating aggregate efficiency benefits; individual participants must also be able to formulate their own business case for participation.

A key challenge is that a day-ahead organized market will utilize the transmission capability of TSPs that fund their respective transmission systems under the existing OATT framework. This includes some TSPs that fund a significant share of their revenue requirements by making sales of long-term OATT service to third-party customers that rely on OATT service for a variety of activities, including to meet their reliability needs, to receive economic value of price spreads between locations, and to make transactions associated with clean and renewable energy products. Because these sales directly reduce the costs borne by native load customers of those TSPs, the risk of cost shifts resulting from a market design that undermines those third-party sales could significantly outweigh the benefits those entities would receive from market participation.

Powerex believes that SPP's Markets+ transmission proposal supports maximum transmission availability while supporting the integrity of the OATT framework by preserving the value of existing transmission rights and preserving incentives for transmission customers to continue to invest in OATT service, with further comments provided in the following areas:

a. Transmission Availability

Powerex supports SPP's proposal to develop a new Market Transmission Service (MTS) to enable a full flow-based regional dispatch across the Markets+ footprint during the day-ahead and real-time timeframe. Powerex believes this approach, combined with the bilateral scheduling functionality and congestion rent allocation approach described below, can enable a complete "cut-over" at the day-ahead timeframe from a contract-path scheduling paradigm to a full flow-based dispatch using the majority of transmission within the footprint (less defined carve-outs).

The draft service offering suggests that individual TSPs will continue to sell OATT service after the day-ahead market timeframe in the same manner as today. During the next phase, Powerex believes SPP and stakeholders should discuss whether real-time transmission sales made by Markets+ TSPs (i.e., to support imports, exports or wheel-throughs across the market footprint) should first require an accepted market award to support any transmission request. This could help to avoid the potential conflict that could arise if Markets+ is producing a real-time flow-based dispatch while individual TSPs are each independently calculating ATC and selling OATT transmission service.

b. Bilateral Scheduling ("Base-scheduling")

SPP's proposal to allow bilateral schedules (e.g., "base schedules") and their associated e-Tags to be submitted prior to the day-ahead market will allow transmission customers to continue to physically schedule on their OATT rights, while not impeding the full flow-based dispatch of the market optimization. This is a key functionality that preserves the ability of entities to continue to deliver specific resources to specific loads associated with forward contracts to meet WRAP obligations or other reliability needs, to document delivery of clean and renewable energy products, and to satisfy legal and regulatory requirements.

c. Congestion Rent Allocation

The conceptual framework proposed for Markets+ will leverage the OATT framework by allocating congestion rent to firm OATT transmission rightsholders. This approach will provide load-serving entities with a hedge against day-ahead market congestion costs, while allowing rightsholders that invest in firm transmission to receive the economic value of delivering energy across constrained paths to receive that value through the allocation approach (instead of by physically scheduling deliveries). Importantly, an approach that is based on transmission rights (not schedules) will ensure that the rightsholders receive the value of their rights while the transmission itself is fully optimized through the economic dispatch.

Powerex believes the next phase of development should address the following topics:

- *Inclusion of Conditional Firm*: Powerex believes it is appropriate to include conditional firm transmission service in the allocation because it is a type of long-term firm PTP service that is comparable to all other long-term firm service, except that it is subject to a lower curtailment priority (NERC priority 6) during a defined number of hours or during predefined system conditions. Conditional Firm can be included in the allocation without diminishing the value allocated to other firm rights because the allocation could be based on NERC priority in the relevant period, with eligible firm network and PTP rights on a particular path receiving their full entitlement first prior to any payout to conditional firm during the periods that it is subject to curtailment at NERC priority 6.

- *Revenue Neutrality:* Ideally, congestion rent allocation would be calculated on a path-specific basis to ensure that each customer receives a payout that reflects the actual capability of their rights (in a manner that is analogous to today, in which a transmission customer's ability to physically schedule on their OATT rights is reduced to reflect derates on that specific path). Powerex understands, however, that a path-specific approach may introduce significant complexity.

  On the other hand, Powerex agrees with SPP that "applying a single ratio to all TSRs could result in some TSRs receiving a lower congestion rent allocation as a result of a transmission derates on unrelated paths." Powerex does not believe that a single ratio across the footprint is workable. For example, it is very likely that derates on key paths— such as the Pacific AC and Pacific DC—would result in very significantly reduced payoffs across the Markets+ footprint.

  Powerex believes that categorizing transmission rights into several "zones" with the Markets+ footprint is a straightforward approach that will largely address the concern of reduced payouts by ensuring that derates to key paths only affect transmission reservations within the same zone, while leaving transmission rights in other areas of the market footprint unaffected. For example, the

Pacific AC and Pacific DC lines could be separated into their own zone(s), ensuring that de-rates on those paths only affect the rightsholders on those lines. A similar approach could be adopted for key sub regions and/or constrained paths in the Markets+ footprint. This approach would also provide flexibility to adjust (or add) new zones as the results of the congestion rent allocation approach are evaluated over time.

In summary, Powerex believes that SPP's Markets+ transmission proposal supports maximum transmission availability while supporting the integrity of the OATT framework by preserving the value of existing transmission rights and preserving incentives for transmission customers to continue to invest in OATT service.

Green House Gas Accounting

The fundamental purpose of a GHG-pricing program is to reduce GHG emissions by imposing a cost on the electricity generated to meet demand under the particular jurisdiction(s) with a GHG-pricing program. The intended effect is to make low- or non-emitting resources relatively more economic than resources that emit high amounts of GHG emissions, creating incentives to shift electricity production to lower-emitting resources, and reducing the total GHG emissions in the GHG area.

Powerex is encouraged and impressed by SPP's dedication of the time and effort necessary to gain a detailed understanding of the challenges of applying GHG pricing programs accurately, particularly with respect to imports into GHG-pricing jurisdictions from areas that do not have GHG pricing programs in place. While this is a difficult challenge and there is no perfect solution, Powerex believes that SPP's service offering establishes three key concepts that should be further developed in the next phase:

1. Preserving the functionality available in the bilateral markets today by allowing specified imports to be base scheduled (with an e-tag) to a GHG zone in advance of the market dispatch (i.e., a "Type I Specified Source Import");

2. Enabling external resources offered into the Markets+ to be assigned as a specified import, provided they are actually incrementally dispatched above an appropriately defined baseline (i.e., a "Type 2" Specified Source Import"); and

3. Providing a framework for unspecified imports to be scheduled while applying a hurdle rate that reflects an appropriate value for of the potential GHG emissions of the imported electricity.

Powerex believes further discussion should focus on developing more detailed proposals for these items, including:

- Appropriate validation of base-scheduled specified-source imports
- Definition of a workable baseline for purposes of measuring incremental output available to be designated as a specified-source import to a GHG zone
- Details of how the market optimization will dispatch both categories of specified source imports
- Defining the unspecified hurdle rate
- Administrative considerations and ensuring compliance with GHG program requirements
- Data, reporting and transparency

Seams issues

It is increasingly clear that two day-ahead organized markets will be operating in the West in the future. Powerex agrees that SPP can provide Markets+ participants with *improved* trade outcomes by establishing a peer-to-peer approach to negotiating seams between markets and establishing a level playing field to represent the interests of Markets+ participants when developing workable approaches to manage those issues. Powerex supports SPP's proposal to develop a seams task force in the coming weeks to begin identifying the specific topics that must be addressed.

Implementation

Powerex understands the timeline for Phase One has been developed with careful planning to provide realistic expectations (with some contingency to resolve issues and seek FERC input), however we are encouraged by stakeholder progress to date and hope participants will be able to drive to a reasonably fast conclusion. We encourage SPP to phase its planning for Phase Two so that participants may elect to fund initial development of the market, in parallel to the final FERC filing stages at the end of Phase One.

We look forward to further discussion of the cost allocation model for funding Phase One in the stakeholder meeting scheduled for November 1.

Conclusion

Powerex is highly encouraged by the progress to date and looks forward to further stakeholder discussion both in Denver in November and in Phase One, Funded Investigation. Powerex offers these comments to further refine the revised Service Offering, however it emphasizes its support for funding Phase One of Markets+.

October 28, 2022

<u>Subject</u>: APS's comments on SPP's Draft Service Offering for Markets+

Arizona Public Service (APS) is encouraged by the Draft Service Offering document SPP released for comment on September 30, 2022. APS supports the direction of the Draft Service Offering overall, is supportive of much of the content, and offers the following comments for consideration and clarification in subsequent iterations.

Governance

APS is overall supportive of this draft's Governance section. An important caveat relies on the composition of entities ultimately committing to participate in some capacity in Markets+. APS recommends that SPP adopt flexibility within its governance structure to ensure that entities are adequately represented once the participant pool is known. The presence and quantity of differing kinds of participants should have an impact on the recognized categories of the Markets+ Independent Panel (MIP) Nominating Committee (identified in section 3.2.3.2.1) and the Markets+ Participant Executive Committee's (MPEC) three-pronged voting structure. Consider the capacity to finalize voting structures following the identification of Markets+ participants and stakeholders.

Regarding the MPEC, APS along with six other Western entities previously advocated for a unicameral approach for the committee's voting structure. Because the MPEC vote is advisory in nature, with the MIP holding decision making authority, APS can support the presented three sector approach to voting. However, a plausible scenario in which voting does not represent accurate geographic diversity may occur based on the identified sectors (investor-owned utilities, public power, and independents). The Desert Southwest could become the minority voice in all areas because of the sector divisions. APS is aware that NV Energy is offering an option with a structure that requires matters to be agreed upon by at least 50% of entities in both the Desert Southwest and Northwest in addition to two-thirds of the SPP identified sectors. APS is similarly cautious about ensuring accurate regional representation. To the extent that SPP protects the MPEC's ability to present minority views to the MIP, APS can remain satisfied that regional perspectives are adequately represented with the existing MPEC voting structure.

Absent from the draft is an explicit timeline for implementation of the governance committees. APS suggests that the MIP, MPEC, and working groups be seated in advance to help develop and prepare the tariff filing with FERC along with other implementation activities.

Lastly, any additional edits and decisions made to the Markets+ governance structure should be adopted to garner the broadest stakeholder consent possible. Of particular significance, APS's governance comments in this document align with stances presented by our neighboring western utilities including Salt River Project, Tucson Electric Power, NV Energy, and Public Service Company of New Mexico.

Market Design

Congestion Rent Allocation: APS has appreciated the detailed and lengthy discussion and workshops on congestion rent allocation. However, the service offering does not include the amount of detail that has been covered in these forums. APS would like to see further incorporation inside the service offering on the topic of congestion rent allocation to document the progress made and to best evaluate the Markets + design for consideration of participating in the next phase of development. APS feels congestion rent, its allocation, and processes related are critical in ensuring entities can move forward in full market participation while protecting their customers and stakeholders from undue risk.

APS would like to highlight areas where more detail could be added, and to reflect the components of congestion rent allocation that we support.

- APS supports a tiered approach to congestion rent allocation to priority 7 network and yearly or longer point to point rights in the first tranche. Network transmission customers pay for their rights based on peak usage amounts and APS believes that the congestion allocation needs to reflect this aspect. We would also support PTP customers, who pay for their full reservation of service at all times, receiving congestion revenues based on their full reservation. The maximum quantity of network transmission rights used for congestion rent allocation is equal to 103% of the customer's network peak load on a yearly basis.
  - A lower tranche of shorter term or lower priority reservations can be utilized for allocation of any remaining funds that were not distributed to the first tranche.
- APS supports an allocation of congestion rent that is associated with the specific source/sink pairs. It is too simple to bucket all rights holders and allocate to holders that may not be exposed to congestion in the market. The allocation should identify those paths that were congested in determining allocations amounts. APS believes that the ability to assign rents reflecting the specific source/sink pairs exposed to congestion will alleviate any concern around potential cost shifts.
- APS supports the ability of participants to select the source and not have SPP perform an assignment from corresponding bid provided to Markets +. This is in part because APS also supports yearly cap establishment for network customers. Also, APS believes that it is typical of ISO/RTO to utilize an annual or seasonal basis in determination of congestion rights, and we do not see the benefits to added complexity of more granular congestion rights.

- APS supports the ability to reflect derates associated with a reservation in the allocation of congestion rents to that reservation holder. A TSP can provide any derated reservation amounts for purposes of re-calculation of the pool of TSR's available for congestion rent.

<u>Convergence/Virtual Bidding:</u> APS believes that convergence bidding delay for a period after market launch is preferred as the market matures in terms of price formation and any flaws in market design can be addressed through the governance framework of Markets +.

<u>Fast Start Pricing:</u> APS is supportive of incorporating fast start pricing into the market design of Markets +. These resources currently provide important attributes to markets and the grid, and in many cases are providing the marginal energy to the market. Incorporating the commitment costs within the LMPs is most reflective of the marginal energy needs of the market and is consistent with almost all RTO/ISO price formation today.

<u>Seams:</u> APS supports the creation of a seams task force to address seams issues between Markets + and external BAA's, organized markets, and TSP's. The seams agreements created by participants with support of SPP will be crucial elements to secure equity and reliability within the Western energy landscape. APS believes that there are two critical seams that must be properly addressed. One is the developing WRAP and the inter-operability of the program with participants external to the Markets + footprint (principles of inter-operability for WRAP included below in our comments). The other is the seam with the CAISO. APS looks forward to further development of addressing seams in the next phase of Markets + and ahead of the launch of Markets +.

<u>WRAP Inter-Operability:</u> APS believes WRAP inter-operability with developing markets is a central aspect for potential participants to have comfort in when committing to participation in these developing markets. APS would like highlight that the equivalent metric to WRAP may be difficult to establish, but if participants elect that option, then a review of what equivalent metric contains is important. APS also supports a must offer requirement that is compatible with the WRAP operational program requirements, but also understands improvements can also be discussed amongst WRAP members and SPP. With members of WRAP participating in Markets+, no market, or another market, it will be of extremely high importance to maintain the principles established below by WRAP members for inter-operability in developing markets.

1. Be designed such that they do not interfere with or preclude participation in the WRAP.
2. Respect the governance framework and decision-making of the WRAP.
3. Preserve the diversity and investment cost savings derived from participation in the WRAP.
4. Preserve the supply priority and OATT transmission priority of WRAP forward showing supply to meet WRAP obligations.
5. Preserve the delivery of diversity benefits (holdback and energy) in the operational timeframe from one WRAP participant to another, including from WRAP participants in one organized market to WRAP participants in another or no organized market.

6. Seek to collaborate with WRAP to ensure compatibility and to achieve potential operational efficiencies and reliability benefits for all WRAP Participants.

Transmission

Market Transmission Service: APS supports the use of market transmission service and working with TSPs to update OATT's to reflect the new service within the OATT. APS also supports the ability for TSPs to recover lost revenue from short-term sales because of Markets +, with the recovery of the lost sales being from energy and load within Markets +. APS requests that SPP establish priority levels of Market Transmission Service levels to NERC defined priorities to assist in the understanding and implementation of priority levels today for transmission service to that which will be established once Markets + is live. APS supports the detailed clarification requests from SRP and agrees the details of this service need to be worked through.

Flow Based Market Operations and Physical Deliverability: APS is supportive of flow-based operations for the transmission system in the Markets + footprint which includes utilizing the transmission system up to its physical limits while also allowing the ability for transmission providers to utilize Service Flow Constraints as an exception if needed. APS supports further development of the necessary changes required to implement this concept into the OATT and what is expected from TSPs for calculation of ATC along with the interactions of any changes with sales of transmission service under the OATT. APS seeks to better understand if SPP will facilitate evaluating the feasibility of short-term (real-time) energy awards to be exported from the Markets + footprint in a flow-based manner, or if this will be done solely by the TSP's participating in Markets +.

Market Settlements

In general, we understand that settlement design is subject to change due to market design changes. We appreciate SPP Market+ provides foresights and details such as numerical examples about settlement in the future workshops to help settlement users to gain an overall understanding on how the market design and optimization solution interacts with the settlement mechanism. APS believes a task force in the next phase of market development is beneficial to enable market participants to highlight detailed areas where Markets + can provide transparent and useful information so that markets design is understood when it rolls into settlements. This would best position Markets + for success as such a complex market launch will inevitably need adjustments, so having information for detailed analysis by settlement teams of market participants for validation will be extremely valuable.

GHG: APS appreciates SPP and interested stakeholders developing the GHG accounting approach contained within the service offering. APS would like further explanation in the service offering on how the "GHG Zonal approach" will impact settlement for both "GHG" and "Non GHG" entities? Please provide examples regarding settlement mechanism on zonal approach model with two-pass solution that is shown on page 52 draft service offering. Will the two-pass solution contain both a pricing and a dispatch run within the baseline and the final pass when GHG zone is allowed imports?

Settlement Timelines: APS reviewed the meter and market settlement timelines within the service offering and believes that the timelines are reasonable. APS previously had concerns about meter data submission timing but believes OD + 4 is feasible at this time.

Constraints in Settlements: How will the various constraints listed on page 49 & 59 such as: Schedule Limit Constraints, Zonal Xfer Constraints, Qualified Path, Physical Energy Constraints/Power Balance Constraints be managed via settlement? APS would support a mechanism for market participant settlement teams to validate the components of constraints that are fed into the marginal congestion component of the LMP. APS understands that this is a complex calculation but would appreciate any transparency that can be provided to identify aspects of the constraints that can be later improved in market design discussions after Markets + launch.

Settlement Categories: APS appreciates the inclusion of settlement categories in the service offering but does request stepping through each market run so we will be able to gain a good understanding of the logic/concept and the integration between Market Design, Market Optimization Solution and how will categories be reflected in settlements. Said otherwise, how does the market result reflect in each settlement category?

APS also request SPP to please provide more details regarding the purpose of the following settlement categories listed on Page 74 of the service offering. Specifically, APS is unsure how the following categories will be utilized in Markets +:

- Over collection of Losses
    - Is this category a neutrality uplift settlement for Losses?
    - On page 24 the service offering states – "Losses will settle under the host transmission service provider with any impacts of losses reduced from Markets+ settlements to avoid double settlement of losses." TSPs currently have loss rates established in OATT while Markets + will calculate a MLC. Is this a mechanism for Markets + to recover the deviation between these two rates, or something else?
- Out-of-merit energy
    - Is this category a result of uneconomical dispatch from SPP as the market operator or is it based on dispatch from individual BAAs through the Markets +?
- Miscellaneous adjustments
    - Please further define what other adjustment charge codes would be a part of Markets +
- Applicable distribution charges
    - Please further define what distribution charges are applicable to Markets +?

In addition to further explanation of these categories, APS believes adding the allocation or distribution method of each category would be valuable (load, market activity, deviators). This will allow market participants to better trace the market design elements through the settlements in terms of what charges or revenues they would expect to see from participation in Markets +.

Market Monitoring

APS continues to support internal market monitoring unit and the application of a conduct and impact-based approach to mitigation if mitigation is a required element of Markets +. APS supports clarification requested by SRP surrounding the MMU determination of mitigation within Markets +, and the need to assess the ability of market participants to exercise market power within Markets +.

Stakeholder Relations

APS is encouraged with SPP beginning to think about possible training elements for Markets + and the customer relations aspect between the market operator and market participants. APS believes this will be an important aspect to further define in towards the end of the next phase, after tariff development and market protocols have been completed.

Implementation

APS agrees and supports SRP's comment on the creation of a task force in the next phase to address the challenges of energy-limited resources in a day-ahead market, specifically natural gas, hydro generation, and storage.

October 28, 2022

Comments from the Clean Energy Buyers Alliance on SPP's Draft Service Offering

Introduction

The Clean Energy Buyers Association (CEBA) is a national association of large-scale energy buyers seeking to procure clean energy across the U.S. With approximately 330 members from across the commercial and industrial sectors, non-profit organizations, as well as energy providers and service providers, who are actively working to create a resilient, zero-carbon energy system.

CEBA supports increased regional coordination in the West, specifically market development efforts structured to support a future West-wide organized wholesale market managed by a Regional Transmission Organization (RTO) or Independent System Operator (ISO). Consolidating utility operations under one market operator that manages transmission and coordinates generation planning could add up to 4,400 megawatts of additional clean energy to the western grid while saving western electricity customers more than $2 billion dollars per year.[1]

CEBA is engaging with regulators, grid operators, and other stakeholders on market design and governance issues as the West continues to increase regional coordination. On July 15, 2022, CEBA submitted comments on SPP's Second Straw Proposal for Markets+ Governance.[2] We are pleased to provide initial comments on SPP's Draft Service Offering,[3] which contains several elements of SPP's Third Straw Proposal for Markets+ Governance[4] and look forward to opportunities to provide feedback on future iterations.

CEBA's Governance Priorities of Large Energy Customers

In previously submitted comments, CEBA requested SPP align its governance proposal with CEBA principles and as well as take an intentional, proactive approach to broaden stakeholder participation. Governance priorities for large energy customers include 1) Independent and responsive grid governance, management, and operation, 2) Transparency, and 3) Broad stakeholder engagement and representation.

Independent and Responsive Grid Governance, Management and Operation

To support independence, CEBA requested SPP expand representation within the Markets+ Independent Panel (MIP) nominating committee to include large energy customers and include

[1] *Western RTO Economic Impact Study Region-Wide Analysis*, Prepared for Advanced Energy Economy by Energy Strategies, LLC, and Peterson & Associates, July 26, 2022.
[2] CEBA Straw Proposal Comments 07/15/2022.
[3] *Markets+ A Proposal for Southwest Power Pool's Western Day-Ahead Market and Related Services*, by SPP Staff published on September 30, 2022. (Hereinafter Draft Service Offering) https://www.spp.org/documents/67974/draft%20service%20offering%20proposal.pdf
[4] *Markets+ Draft Governance Straw Proposal Version 3.0l*, by SPP Staff published on September 27, 2022. https://spp.org/documents/67948/09272022%20version%203.0%20final%20clean.pdf

other non-voting members. CEBA supports the new addition of a seat for "large energy and industrial customers"[5] representative on the MIP Nominating Committee as this seat provides important representation for our stakeholder group.

Transparency

In order to maintain transparency in Markets+ governance, CEBA requested SPP provide all stakeholders with access to market issues and decision making through open meetings, advanced notice, and meeting recordings or minutes. CEBA supports the additional clarifying details recently added on how closed meetings for the MIP and Market Participant Executive Committee (MPEC) will be utilized. The Draft Service Offering states "Matters for consideration in closed or limited session *are* limited to personnel, legal and proprietary, confidential or security sensitive information"[6] for MIP and MPEC meetings. The Service Offering should harmonize the language used for working groups and task forces, which currently states "Matters for consideration in closed or limited session *should* be limited to personnel, legal and proprietary, confidential or security sensitive information."[7]

Additionally, CEBA reiterates that large energy customers and other stakeholders should be able to track market issues, raise new concerns, and understand the basis upon which decisions are made. At a minimum, the Draft Service Offering should also explicitly require all Markets+ bodies, including working groups and task forces, to enhance transparency by posting materials such as slides and meeting summaries so that stakeholder participation is meaningful.

Broad Stakeholder Engagement and Representation

In furtherance of establishing and broadening stakeholder engagement and representation in Markets+, CEBA asked SPP to clarify membership requirements including large energy customers, adopt the streamlined unicameral voting structure put forth by NIPPC, remove membership fees for non-market participant stakeholders, and allow non-market participants to vote in working groups and task forces.

In our previous comments, CEBA requested additional clarification that large energy customers with load greater than 1 MW are eligible to become voting members within Markets+.[8] CEBA again requests more information on how SPP proposes to define large loads as the current Draft Service Offering defines a Markets+ Market Participant as "an entity that has executed a Markets+ market participant agreement as part of the Markets+ tariff and contributes generation and/or load to the Markets+ market"[9] but is unclear whether contributing load is limited to load serving entities or would also include large customer load.

CEBA supports the streamlined stakeholder structure included in the Draft Service Offering, which now includes a sector for "Independents," where large energy customers would

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[5] Draft Service Offering, Page 10.
[6] Draft Service Offering, Page 12 and14.
[7] Draft Service Offering, Page 16 and 18.
[8] CEBA Straw Proposal Comments 7/15/2022, Page 4.
[9] Draft Service Offering, Page 6.

presumably participate. CEBA requests more clarity in the sector definition, which currently states "Independents: This sector includes Markets+ market participants that are not an IOU or a public power utility and Markets+ market stakeholders."[10] This definition should be refined to more clearly include Markets+ market stakeholders. CEBA offers the following: "Independents: This sector includes Markets+ market participants and stakeholders that are not an IOU or a public power utility." CEBA is also interested in exploring an idea set forth by other stakeholders proposing an advisory board for public interest organizations.[11]

Meaningful participation in market governance requires stakeholder decision making that is efficient and balances representation. CEBA supports voting structures that do not give any parties outsized influence over decision-making. Sector-weighted voting should be designed to reasonably balance positions and should not allow one sector to dominate decision making. CEBA welcomes input from other stakeholders on how to refine voting structures to improve and fairly balance stakeholder representation.

CEBA is concerned that key stakeholders could be excluded from the "phase one stage" included in the Draft Service Offering, which adds a financial commitment requirement, and strongly opposes any additional barriers to participation.[12] The scope of activities listed for phase one include governance design and partial implementation.[13] Specifically, SPP plans to leverage "components of the governance framework to create stakeholder processes, facilitated by SPP staff, which provide structure and voting mechanisms."[14] CEBA requests clarity on how participation in phase one will be managed and when this phase will be initiated in order to understand possible implications for stakeholder participation.

Large energy customers should be afforded this level of transparency whether they are engaged as official voting members or non-voting stakeholders. The current draft service offering still maintains a $5,000 fee for Markets+ Non-Voting Stakeholders. It also excludes Markets+ Non-Voting Stakeholders from participation in Working Groups and Task Force. CEBA believes that reducing barriers to stakeholder participation, such as the removal of fees and the inclusion of non-voting stakeholders in working group and task force participation/voting, are critical steps to ensuring representation and diverse points of views within these Markets+ bodies.

Finally, CEBA applauds SPP for including elements of adaptable governance, such as "review of the Markets+ market governance in light of accumulated experience and changed circumstances."[15] While voting structure changes are included in changed circumstances that might warrant the review be initiated by the MPEC, the stakeholder groups themselves should have the ability to initiate a governance review considering they can best assess whether or not viewpoints have become divergent within their stakeholder group or if the structure has become

[10] Draft Service Offering, Page 15.
[11] NIPPC Straw Proposal Comments 7/15/2022 Page. 3.
[12] Draft Service Offering, Page 86.
[13] Draft Service Offering, Page 87.
[14] Draft Service Offering, Page 86.
[15] Draft Service Offering, Page 20.

unworkable. CEBA strongly supports the use of a sector-based committee to develop recommendations for governance revisions.

Organized Wholesale Markets Principles and Market Evolution

CEBA's written comments and engagement have thus far focused on governance elements. As the Draft Service Offering integrates all components of SPP Markets+ design: Governance, Market Products and Price Formation Design, Transmission Availability, and Green House Gas (GHG) Design, we look forward to engaging across these topics. CEBA emphasizes the need for these market design details to align with large energy customers principles.

Unlocking Wholesale Market Competition to Catalyze Clean Energy

Well-designed and effectively implemented organized wholesale markets can be instrumental in catalyzing clean energy resources. Markets operate most effectively when based upon competitive principles, including:

1. **An open and level playing field**.

   All generation, storage, demand-side management, and other resources should be permitted to provide all services they are technically capable of providing.

2. **A role for demand participation**.

   Meaningful avenues for demand-side resources to participate, as well as incentives for responsiveness to the time and geographic-specific costs of electricity use, can reduce system costs for customers and incentivize efficient and emission-reducing investments.

3. **Services that provide actual value to customers**.

   Customers should only pay for services that provide value. Organized wholesale market design should be based on market pricing, cost causation, and supply and demand principles, which allow a market price for services needed by demand.

Designed to Scale to the Future

Market design should be constructed in recognition of the increasingly flexible, decentralized, and clean energy sector of the future, built to secure:

1. **Largest efficient operational scale available.**
   Because markets function more efficiently on larger scales, single larger geographic market footprints are preferred over multiple smaller ones. An independent operator should provide organized wholesale electricity services through competitive organized markets and oversee transmission operation and planning.

2. **Options for customers.**
   Markets should have mechanisms that permit customers to meet decarbonization commitments and facilitate efficient bilateral contracting.

3. **Respect for federal and state public policy.**
   Markets should facilitate and harmonize with other federal and state policy choices.

4. **Predictable investment decisions.**
   Market rules should be designed with durability and predictability in mind. Market rules may need updating over time, but changes should be minimized and avoided without a clear showing of need.

Conclusion

CEBA views SPP's Markets+ offerings as an important step towards the goal of establishing a West-wide Regional RTO/ISO that is both well-designed and well-implemented. Overall, SPP should continue to work closely with stakeholders on both governance and market design issues while anticipating the evolution of this market offering.

Respectfully Submitted,

/s/ Adrienne Mouton-Henderson

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October 28, 2022

Comments of the Colorado Energy Office
On the SPP Markets+ Draft Service Offering of Sept 30, 2022

The Colorado Energy Office (CEO) respectfully submits the following comments in response to the Markets+ Draft Service Offering. CEO is an agency within the executive branch of the State of Colorado with the mission of reducing greenhouse gas emissions and consumer energy costs by advancing clean energy, energy efficiency, and zero emission vehicles to benefit all Coloradans. CEO is also tasked with advancing the state's clean energy agenda to help meet economy-wide greenhouse gas emissions reduction targets of a 26% reduction by 2025, 50% reduction by 2030, and 90% reduction by 2050 from 2005 levels. These reduction targets are most immediate in the electricity sector, where state law requires certain electric utilities that own and operate generation to meet an 80% reduction from 2005 levels by 2030, and a 95% reduction by 2050.

CEO recognizes the important work the Southwest Power Pool (SPP) has been doing in creating electricity market offerings in the western interconnection, including the extended day ahead market of the Markets+ framework. CEO continues to be interested in this proposal and appreciates the opportunity to participate in the market development process. This is a timely process as this and other markets are being designed in the West while the state's transmission utilities are working with the Public Utilities Commission (PUC) to comply with Colorado Senate Bill 21-72, which requires these utilities to join an Organized Wholesale Market (OWM) by 2030 or to demonstrate to the PUC why participation is not in the public interest. An OWM is a subset of RTOs and ISOs that meet ten statutory requirements, including: that market participation decreases customer costs, increases reliability, and reduces emissions; includes transmission and generation resources needed to attain those emissions reduction targets; and has an open and inclusive stakeholder process. In prior comments, CEO requested that SPP clarify on the participation of state agencies, account for state energy policy requirements, and expand the GHG zones to states with state-wide or electricity sector greenhouse gas (GHG) emissions reduction targets. CEO continues to have concerns that SPP has not made significant changes or updates in the governance structure, the potential for states without cap and trade programs to participate in the GHG zone proposal, or in its approach GHG tracking.

CEO provides comments on the following:

I. Requirements of Colorado Senate Bill 21-72 and relationship to the Markets+ design
II. Governance
III. Addressing the needs of states with greenhouse gas reduction targets
    A. Expanding SPP's proposal on GHG zones
    B. Business case for including carbon intensity as a dispatch metric
IV. Greenhouse gas accounting rules for Colorado

I. Requirements of Colorado Senate Bill 21-72[1] and relationship to the Markets+ design

CEO recognizes that Markets+ is not a full RTO. However, we believe that Markets+ can and may set a foundation for a future RTO or ISO and thus it is important that SPP as the market operator makes every effort to set that foundation in a way that supports participation from Colorado utilities that are obligated to pursue participation in an OWM. The proposed changes may also facilitate the process of transmission utilities from other states, including states that have similar laws in place, such as Regulation 448 in Nevada.[2] CEO's recommendations around addressing GHG emissions may find support as well from states such as Oregon, New Mexico, and Nevada, that have GHG emissions reduction targets or renewable portfolio standards.

The ongoing Colorado PUC rulemaking docket 22R-0249E[3] is a rulemaking proceeding for Colorado transmission utilities to join an OWM. This proceeding is focused in large part on the standards for markets to meet the ten OWM characteristics. Several of these characteristics would likely apply to all RTOs, ISOs, and even proposed day ahead markets (DAMs). These include (I) FERC approval, (II) transmission and generation controlled separately, (III) minimized pancaked transmission rates, (IV) improves electricity reliability in Colorado, (V) reduces electricity costs for Colorado customers, and (VI) governance that is independent of ownership of the transmission facilities.

The remaining OWM characteristics may require analysis of a specific utility participating in a particular market including one on customer benefits, one on greenhouse gas emissions reduction, one on generation sources that reduces emissions, one on open stakeholder engagement and one on transmission planning (bold added by CEO):

VII. **Improves emission-reduction and customer-savings benefits to Colorado customers** from operation within the Western Interconnection without significantly impairing actions taken by Public Utilities **to meet the emission-reduction goals** of sections 25-7-102 and 40-2- 125.5 and to continue to advance the objectives of those sections;

[1] *Public Utilities Commission Modernize Electric Transmission Infrastructure. Senate Bill 21-072. (Colorado) 2021*. Sen. Chris Hansen, Sen. Don Coram, Rep. Alex Valdez, Rep. Marc Catlin. https://leg.colorado.gov/bills/sb21-072

[2] *Senate Bill 448. 2021.* (Nevada). Sen. Chris Brooks. Section 26, 1-11. https://www.leg.state.nv.us/App/NELIS/REL/81st2021/Bill/8201/Text.

[3] Colorado Public Utilties Commission. Docket 22R-0249E. Opened June 6, 2022. Available at: https://www.dora.state.co.us/pls/efi/EFI.homepage

VIII. **Has an inclusive and open stakeholder process** that does not place unreasonable burdens on, or preclude meaningful participation by, any stakeholder group;

IX. **Includes all transmission and generation resources** approved, acquired, or constructed and in service by 2030 **to meet the emission reduction requirements** of sections 25-7-102 and 40-2-125.5; and

X. **Consistent with and in support of FERC policies and orders and local planning by Colorado public utilities**, is capable of: **planning for improved efficiency of use, future expansion, and consideration of all options for meeting transmission needs**; providing effective cost allocations that reflect benefits of transmission investments; maintaining real-time reliability of the electric transmission system while promoting more efficient use of the transmission system in Colorado and neighboring areas in the Western Interconnection; ensuring comparable and nondiscriminatory transmission access and necessary services; minimizing system congestion; and further addressing real or potential transmission constraints.

CEO recognizes that SPP submitted response comments in the aforementioned Colorado PUC OWM rulemaking[4]. However those comments did not address how the Markets+ proposal does or does not align with the 10 OWM characteristics.

<u>II. Governance</u>

CEO appreciates SPP's recognition of the importance of stakeholder engagement. However, CEO suggests that a more robust role for stakeholders and, most importantly to CEO, a role for state agencies to help influence market policy, are important next steps.

CEO recognizes the changes that SPP has made in the Markets+ governance structure, including waiving the $5,000 fee for NGOs to participate in the Markets+ Market Stakeholder (MMS) group, and that the Markets+ State Committee (MSC) allows each state's PUC to name one state representative from that state. Despite these changes, the level of potential participation by the states and NGOs is too limited in scope.

Colorado statute requires open and inclusive governance. Despite several minor changes to the governance structure, the current proposal for Markets+ severely limits the participation of the states and other non-utility stakeholders in the decision making

[4] *Southwest Power Pool, Inc.'s Reply Comments on Proposed Rules.* Sept. 20, 2022. Colorado PUC Docket 22R-0249E

process. CEO recognizes that in the current proposal, the Markets+ State Committee representative from each state need not be a commissioner, but is nominated by the state regulatory commission. However, this approach is too limited to reflect the diversity of perspectives represented by the agencies of each state. Further, CEO suggests that the governance model should include more than just Markets+ participants[5] but should include a broad array of stakeholders (including rate paying customers, state regulators, state agencies, NGOs, and tribes) to ensure the participation by utilities in the market benefits those stakeholders, and not just the utilities.

When incorporating states with varying statutes, it is critical to give voice to the state agencies in the market decision making process to ensure that these statutes are recognized and observed. It is important to recognize that the shift to electricity markets transitions much of the state's authority to the regional level, which is highly concerning to states like Colorado that have highly effective and collaborative utility regulatory practices in place.

III. Addressing the Needs of States with GHG Targets

CEO does appreciate the work that SPP has done to create the "GHG zones," which would incorporate the cost of emissions into the electricity costs, thereby giving preference for non-emitting generation sources for utilities in states that are part of the zone. However, it appears that the GHG Zone definition is confined to states that implement a carbon price through a cap and trade program for greenhouse gas emissions, which only currently includes the States of Washington and California. CEO understands that this has been the primary focus of SPP's GHG accounting development thus far. This approach incorporates economic policy considerations but does not seem to account for the environmental policy drivers in states like Colorado. This current proposal is helpful to address some GHG emissions reduction targets, yet too narrow in scope because it excludes all other states without a pricing mechanism on emissions.

A. Expanding SPP's Proposal on GHG Zones

CEO is interested in the GHG Zonal approach presented in SPP's Markets+ proposal, but is concerned about the inability for Colorado utilities, and utilities in states that may have similar greenhouse gas reduction targets, to participate in that structure. We believe that not being able to participate with other states that share similar interest in and commitments to GHG reductions would likely impede the state's ability to meet its greenhouse gas emissions reduction targets. Despite the fact that nearly all of the commenting parties on the August 26, 2022 Markets+ draft proposal requested greater

[5] SPP Markets+ Design and Transmission Availability Sessions Working Draft Version 0.2, page 4. August 26, 2022.

clarity on the GHG zonal approach and GHG accounting, minimal if any updates were made in that section between that draft proposal and the current proposal.

CEO offers two approaches that we believe provide pathways to help states that have GHG targets meet those targets within a market. CEO also provides a recommendation on how SPP could address GHG accounting in states without cap and trade systems on carbon emissions.

The first is the expansion of the zonal approach. CEO suggests removing the requirement that a state have a cap and trade or carbon tax system in order to participate. CEO believes that it would be reasonable to set a threshold for participation that a state has either an economy-wide or electricity sector GHG emissions targets. Alternatively, as Public Service of Colorado proposed in its Sept 16, 2022 comments, the GHG zonal approach could be adopted even by balancing authorities or individual systems.[6] This expansion of the GHG zones would allow states to increase their reliance on renewable energy resources by first serving themselves with their renewable energy, then serving each other, then finally importing the remaining electricity from the market.

As a part of the GHG zonal expansion proposal, the shadow price used in the expanded GHG Zones could be determined by a group of states, an individual state, or a balancing authority. For example, in Colorado there may be an interest in utilizing the designated social cost of carbon.[7] Colorado statute indicates that the 2.5% discount rate be utilized.[8] Other valuations of that shadow price for GHG emissions could be further clarified in the next phase of the Markets+ development.

If SPP did not want to expand the GHG Zones, CEO believes that assigning a carbon intensity of each MWh that is offered on the market for sale could help states that have GHG targets understand the impact of market imports on the state or utility emissions requirements. Normally, the two metrics that are attached to the e-tags of MWhs on the market are price and load. This proposal is that SPP, market participants, and the Western Renewable Energy Generation Information System (WREGIS) should include an anticipated carbon intensity metric of the electricity in SPP's markets as a third metric. Market participants can use this metric in their electricity purchase decisions in order to ensure they will be able to meet their specific IRP emissions reduction requirements and

[6] Public Service Company of Colorado's Comments on Markets+ Working Draft, September 16, 2022, page 3.
[7] Interagency Working Group on Social Cost Of Greenhouse Gases. United States Government. Feb. 2021. Appendix, page 0.
https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf?ftag=MSF0951a18
[8] § 40-3.2-106(4). C.R.S.

further state policy goals. The business case for this carbon intensity metric inclusion at the dispatch level of the market is described in more detail below.

B. *Business Case for including Carbon Intensity as a Dispatch Metric*

Problem: The Southwest Power Pool does not include the carbon intensity in the metrics associated with the planned dispatched electricity in its market. This makes it difficult for utilities in states that have greenhouse gas reduction requirements, but no price on carbon, to make informed decisions as to the dispatch selection to meet those targets.

Proposed solution: SPP, market participants, and the WREGIS, operated by the Western Electricity Coordinating Council (WECC) should include an anticipated carbon intensity metric of the electricity in SPP's markets as a third metric, in addition to the energy demand and cost metrics. Market participants can use this metric in their electricity purchase decisions in order to ensure they will be able to meet their specific IRP emissions reduction requirements and further state policy goals.

Background: Colorado utilities have either joined or are planning to join the SPP WEIS market, and are contemplating participation in both the extended day ahead Markets+ and the SPP RTO West. Currently, most of the SPP's Markets+ GHG accounting focus is on states in which there is a price on emissions, which can easily be incorporated into the cost of the electricity in those "GHG Zones." Less emphasis is being placed on developing systems that would encourage market participants, especially in states with emissions reduction targets yet without carbon prices to select dispatched electricity with lower carbon intensities.

Why : The State of Colorado and other states in the West have statutory targets for the electricity sector to reduce carbon emissions. Allowing any market that Colorado utilities participate in to provide and receive carbon intensity estimates on the day ahead and real time markets will better allow these utilities to support their required emissions reductions in their approved IRPs.

How: The generator participating in the market would be required to submit an estimated carbon intensity value associated with the energy sources being offered into the market from that resource or group of resources if the energy available is an aggregate of multiple resources. The units for carbon intensity are metric tons carbon dioxide equivalent per megawatt-hour ($MTCO_2e/MWh$).

CO_2e is a combination of the emissions of each of the greenhouse gasses produced from fuel combustion, which are carbon dioxide (CO_2), nitrous oxide (N_2O) and methane (CH_4). The quantities produced of each GHG per MWh would be multiplied by their respective global warming potentials (GWP), then added together. The carbon intensity could be calculated using historical emissions reported to the EPA, by dividing the total emissions from the most recent annual total by the total MWh produced by that generator for that year. The most important determining factor in carbon intensity is the fuel source for generation. Table 2 has default carbon intensities by fuel source. Actual carbon intensities will vary by generation resource based on age, technology, type of coal, maintenance, generator efficiency, and other factors.

Table 1: Global Warming Potential (GWP) by GHG

GHG	GWP CO_2 eq.
CO2	1
CH4	230
N20	273

source: EPA[9]

Table 2: Default Carbon intensities by fuel source

Fuel	$MTCO_2$ e/MWH
Coal	1.01
Natural Gas	0.41
Wind	0
Solar	0

source: EIA[10]

[9] US Environmental Protection Agency. *Understanding Global Warming Potentials*. May 5, 2022. https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why

[10] U.S. Energy Information Administration. *FAQ: How much carbon diozide is produced per kilowatthour of U.S. electricity generation? https://www.eia.gov/tools/faqs/faq.php?id=74&t=11*

What it would accomplish : This would allow market participants to use the carbon intensity metric in addition to cost and load when deciding to make purchases or sales in the market. This will help improve the utility decision-making process, as they work to meet complex and evolving standards and goals established by federal and state laws and regulations, approved resource plans, clean energy plans, customer preferences, or other policies.

Additionally, this would help to reduce uncertainty about the emissions associated with the electricity imported into a given state. This will make the GHG accounting process more transparent, accurate, and understandable.

Challenge: There are three challenges that would need to be addressed in developing this process:

1) Unspecified generation source carbon intensity - There would need to be a system agreed to upon by the market participants to assign the MWhs from unspecified sources. In the most rudimentary level, this could be an annualized average of the aggregate carbon intensity from the market or originating state. The level of sophistication could be up to an average of the real-time average carbon intensity of the resources on the market at that time in one hour or five minute increments. The preferred alternative would be that the highest level carbon intensity (coal) would be the default for unspecified source imports. This would provide an incentive for the market operator and participants to minimize the amount of unspecified source exports and imports.

2) Market operators and reporting structures - This process would require updates to the market processes to include and evaluate this additional information tied to the MWhs being sold and purchased in the market. However, these markets are highly developed data centers. Updating the metrics associated with electricity in the markets can be included in order to support utility and state policies regarding GHG emissions.

3) Carbon intensity for a particular generation unit may vary based on where in the acceptable generation range the actual generation occurs. In general, the efficiency levels of fossil fuel generators decreases as the generation level decreases from the maximum generation level, thereby increasing the carbon intensity of a particular MWh. Therefore, an historical average carbon intensity for each generation unit could be used for all dispatch from that unit, based on an average `from the previous year.

Decision point: If SPP would like to incorporate utilities from the state of Colorado and other states with GHG emissions reduction goals into Markets+ and other market offerings, systematically providing carbon intensity metrics through the electricity market dispatch process adds tremendous value to the decision making of these utilities and will be essential for them to be able to plan effectively to meet state policies.

The utilities in Colorado serve 5.5 million people, equivalent to over one quarter of the current customers served by the current SPP RTO. The State of Colorado has established the statutory requirements that emissions associated with electricity consumption in the state be reduced by 80% by 2030 from the 2005 baseline.[11] The Colorado General Assembly passed SB 21-72, which encourages Colorado utilities to join an OWM. An OWM is a subset of RTOs and ISOs that meet ten characteristics. One of these characteristics is to improve emission reduction goals of the state of Colorado. In order to evaluate the ability of Markets+ or the SPP RTO West to assist in meeting these emissions reduction targets, understanding the carbon intensity of the resources available in the market at dispatch is critical.

IV. Greenhouse gas accounting rules for Colorado

The current proposal's focus on greenhouse gas accounting is currently quite vague in its approach, leaving most of the work up to future discussions. CEO recognizes SPP's request "to establish and implement business rules needed to associate generation production with load consumption by state or region."[12] The goal of this section is to engage the SPP Markets+ development team in understanding the greenhouse gas reporting requirements in the state of Colorado. Understanding these requirements for Colorado and other states that have similar requirements will be critical if SPP hopes to gain the participation of utilities from these states in this new market.

Colorado's GHG reporting rules are part of the Colorado Air Quality Control Commission's (AQCC) regulation Part A § IV.C.[13] This regulation requires emissions tracking "associated with imports and exports in order to attribute GHG emissions from electricity delivered to customers in the state of Colorado, and determine GHG emissions from electricity exported out of the state". It also mandates the use of a supplemental data form required.[14] This form requires carbon intensity, measured in pounds of CO_2e/MWh, for all market

[11] § 40-2-125.5(3)(a)(I), C.R.S.
[12] SPP Markets+ Draft Service Offering of Sept 30, 2022, page 60.
[13] Colorado Air Quality Control Commission, Colorado Greenhouse Gas Reporting and Emission Reduction Requirements Regulation, Part A, IV.C., https://cdphe.colorado.gov/aqcc-regulations.
[14] Colorado Greenhouse Gas Reporting Form: https://cdphe.colorado.gov/air-pollution/climate-change#reporting.

transactions. This regulation also requires electric service providers or electric utilities will "use the most specific data sources in the published form for assigning GHG emissions to imports and exports of unspecified energy, electricity acquired through contract obligations, market electricity purchased or sold from a pooled group of resources."[15] The data sources must be pre-approved by the Colorado Department of Public Health and the Environment (CDPHE) Climate Control Division. Leaders of this division were the originators of the carbon intensity metric at dispatch proposal above.

The total GHG emissions levels by Colorado transmission utility must include GHG reductions as approved by the PUC in each utility's Clean Energy Plan. These plans were individually litigated and approved by the Colorado PUC. The utility and market must describe the GHG accounting methodology used in the collection of the data.[16]
The statutory requirements for GHG accounting in Colorado and other states is explicit and requires engagement by the SPP Markets+ design team in understanding and complying with the varying state-level requirements.

CEO agrees with Public Service Company of Colorado in their comments on Markets+ Working Draft, that "SPP include carbon emissions reporting in the service offering for any entity in the market who requests it - regardless of whether the entity is in a GHG zone."[17] The preferred approach to GHG accounting by SPP and Markets+ by CEO would be to include a carbon intensity metric to enhance dispatch optimization, as proposed above.

CEO appreciates the opportunity to engage with SPP in the development of Markets+ and we respectfully submit these comments in hopes that they will be considered and the necessary changes will be adopted into the Markets+ final proposal.

Sincerely,

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Colorado Energy Office

John Parks
Electricity Markets & Transmission Policy Analyst
Colorado Energy Office

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[15] Colorado Air Quality Control Commission, Colorado Greenhouse Gas Reporting and Emission Reduction Requirements Regulation, Part A, IV.C.1.a.(iii), https://cdphe.colorado.gov/aqcc-regulations.
[16] Colorado Air Quality Control Commission, Colorado Greenhouse Gas Reporting and Emission Reduction Requirements Regulation, Part A, (IV.C.2.b.(ii)), https://cdphe.colorado.gov/aqcc-regulations.
[17] Public Service Company of Colorado's Comments on Markets+ Working Draft, September 16, 2022, page 3.

COMMENTS OF THE STATE PUC MOU GROUP ON M+ GHG PROPOSAL

Friday, October 28, 2022

The undersigned commissioners of the Western Public Utility Commissions' Joint Action Framework on Climate Change ("State PUC MOU Group") appreciate the opportunity to provide SPP with these comments on the Markets+ GHG Proposal[1]. We note that these comments are not binding on the undersigned commissioners in any state or federal regulatory proceeding concerning any matter related to Markets+.

Incorporating Non-Priced GHG Programs into Markets+

The Zonal approach for Markets+ described in the DSO addresses cap-and-trade programs, which exist currently only in California and Washington. The DSO does not address other non-price-based clean energy standards that are the law in Oregon, Nevada, Colorado, and New Mexico. We understand that because these programs are not price-based, they are not readily accommodated in a price-based market. Nevertheless, these programs directly impact the ability and way in which affected utilities can participate in Markets+.

The six states represented in the State PUC MOU Group (Washington, Oregon, California, Nevada, Colorado, and New Mexico) have a variety of clean energy programs to reduce GHG emissions in the power sector in addition to the cap-and-trade programs of California and Washington. There are Renewable Portfolio Standards (RPS) which require a certain percentage of a utility's load to be served from renewable resources, with the percentage increasing over time to a maximum percentage depending on the state's specific legislation (e.g., New Mexico's RPS maximum is 80% by 2040). There are also GHG Reduction Programs, which are typically structured as a maximum percentage in the GHG emissions of the electricity serving the utility's load, measured against a base-year, with the percentage decreasing over time to zero percent. i.e., 100% clean energy resources serving load subject to certain exceptions and alternatives depending upon the state's legislation. These laws function as carbon emission limits, just as the cap-and-trade programs do.

Meeting RPS Obligations in a Day-Ahead Market

There are concerns that arise as states which have no previous experience with day-ahead markets begin to recognize the implications for imports and exports through the market for utilities obligated to meet a certain percentage of their load with renewable energy. Without legislated carbon constraints, many of our states have not focused on how REC ownership transfers might implicate imputed carbon in the remaining energy when it is dispatched by the market to a neighboring state with a carbon limit. As each state implements its own carbon regulation, sometimes described as clean energy standards, we face

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[1] A Proposal for Southwest Power Pool's Western Day-Ahead Market and Related Services (Draft Service Offering – DSO), September 20,2022, p.51-52.

the learning curve and challenge. California addressed this issue when it implemented its carbon market and chose to count carbon in one program (the cap-and-trade program) and RECs in a different program (the RPS). It is unclear how some states will manage through this integration challenge and is a moment of transition. Fundamentally this raises the need for continued dialogue and understanding so that our respective accounting systems mesh with environmental integrity and clarity. Additionally, any allocation of renewable energy the market operator imputes to market participants that they then use to make a 'renewable' claim may need to be cognizant of the actual flow of Renewable Energy Certificates (RECs) if it is to comply with state law and not inadvertently erode RPS compliance for other participating entities. Finally, the region may benefit from coming to a common understanding of how to count the various claims on the zero-carbon nature of the renewable energy under our legislated carbon goals. Differing legal frameworks will create

complexity for the market that will be difficult to address.

Meeting GHG Reduction Standards in a Day-Ahead Market

GHG reduction standards in Colorado, Nevada, and Oregon represent a different challenge since GHG reduction standards rely on counting carbon in electricity used to meet a compliance target, rather than counting RECs to meet the compliance target. This implies that a utility subject to GHG reduction standards must have some degree of control over what resources are being used to meet its load. This would not necessarily be an immediate concern since near-term compliance could likely be met through counting emissions of the utility's own dispatched resources and the average emissions rate of imports when the utility is a net importer. However, this strategy would eventually require the utility to limit its imports through self-scheduling of its own resources. Ultimately, a utility's compliance level would require it to self-schedule almost all its load, calling into question how much benefit it is gaining by being a Markets+ participant. The market operator reporting on imputed GHG emissions alone is likely insufficient to resolve this issue.

It has been proposed by the CAISO that a constraint could be implemented in the EDAM optimization that would allow a load-responsible entity to limit imports based on emissions. While a constraint like the one proposed by the CAISO may not be needed in the early releases of Markets+, the first hard compliance deadlines are in 2030 and continuous reporting, reductions and planning by the utilities is required throughout the 2020s. We recommend that the next phases of Markets+ development incorporate thinking, discussion, and future planning amongst stakeholders on similarly facilitating GHG reduction programs for utilities subject to them.

The Zonal Approach for Implementing Cap-and-Trade in Markets+

The DSO specifies that if there is a market participant in a cap-and-trade state, the preferred approach for implementing cap-and-trade obligations into market optimization would be through the Zonal approach. However, the DSO contains very little detail on how the Zonal approach would be implemented, deferring those decisions to the next, participant-funded phase of development over the coming 21 months culminating in the FERC filing. We therefore reserve comment on the specifics of Zonal approach as those specifics are defined. We highlight how critical it will be to remain engaged with state agencies, both air regulators and utility commissions throughout that design process.

However, there are several questions about the operation of the Zonal approach which we recommend be taken into consideration as the Zonal approach is developed over the next 21 months.

1. What are the criteria for a resource to be eligible to bid through a specified path into a GHG zone?
2. What entity will be responsible for acquiring the necessary allowances for imports through the unspecified path?
3. The DSO says that GHG compliance will be captured separately from the LMP. Does this mean that the allowance costs will not be incorporated into the dispatch optimization through the unspecified path, in other words, that emissions costs are calculated after the fact based on actual measured emissions?
    a. If allowance costs will be incorporated, will this not impact the LMPs of the GHG zone?
    b. If allowance costs will not be incorporated into the unspecified path bids, does that not put resources in the specified path at an "unfair" disadvantage? Would this not also put clean energy resources coming through the unspecified path at a disadvantage to emitting resources coming through the unspecified path?
4. How will the emissions rate (mtons CO2/MWH) that is applied to imports through the unspecified path be developed?
5. How will gross emissions (mtons CO2) of imports through the unspecified path be measured?
6. How will the Zonal approach treat resources that are outside of a GHG zone and serve load both within a GHG zone and load outside a GHG zone, e.g., certain resources throughout the western states are divided on a percentage basis between multiple load-responsible entities.

Signatories

Honorable Eric Blank, Chair, Colorado Public Utility Commission

Honorable Tammy Cordova, Commissioner, Nevada Public Utility Commission

Honorable C. J. Manthe, Commissioner, Nevada Public Utility Commission

Honorable Ann Rendahl, Commissioner, Washington Utilities and Transportation Commission

Honorable Letha Tawney, Commissioner, Oregon Public Utility Commission

Honorable Hayley Williamson, Chair, Nevada Public Utility Commission

COMMENTS OF THE STATE PUC MOU GROUP ON M+ GOVERNANCE PROPOSAL V3

Friday, October 28, 2022

The undersigned commissioners of the Western Public Utility Commissions' Joint Action Framework on Climate Change ("State PUC MOU Group") appreciate the opportunity to provide SPP with these comments on the Markets+ Governance Proposal version 3. We appreciate that SPP has acknowledged our concerns with earlier versions of the Governance Proposal and has responded by making several significant improvements to the proposal. We note that these comments are not binding on the undersigned commissioners in any state or federal regulatory proceeding concerning any matter related to Markets+.

We have organized these comments by addressing specific elements of the proposal in the following sections.

M+ Market Stakeholders (MMS)

Version 3 of the proposal proposes that MMS's may now vote in the Markets+ Market Participant Executive Committee (MPEC). While we endorse this proposed change, please see our comments under the MPEC section. Version 3 also proposes that the annual fee of $5000 "*may* be waived for *eligible* entities that are non-profit organizations under the Internal Revenue Code.[1]" As noted in the above quote, the wording of this definition uses "may" and "eligible" which would imply some further criteria will be used to determine whether the fee will be waived for an individual organization. Our comments on July 15, 2022 suggested a PIO definition rooted in the IRC Section 501-c3, recognizing a wide range of organizations may be designated non-profit under other sections of the code. We request SPP to provide further detail in the definition of M+ Market Stakeholder on the criteria that would be used to determine which non-profit organizations will be eligible for fee-waiver.

M+ Market Participant Executive Committee (MPEC)

Our understanding of the proposed MPEC voting procedure is that it would be based on three sectors: Investor-Owned Utilities (IOU); Public Power (PP); and Independent, which is any MMS not an IOU or PP. Voting on a proposal before the MPEC would be by sector: each sector's vote would be tabulated as the number of sector members approving divided by the number of sector members voting. The three sector votes would be averaged for a final vote. The proposal would be approved by the MPEC if the final vote was at least 67%.

[1] Markets+ Draft Governance Straw Proposal, Version 3.0, p.2, September 27, 2022.

We believe this voting structure is superior to the House-Senate style voting which had been considered for the MPEC. However, we have certain concerns about this voting structure:

1. The Independent sector is very broadly defined and will likely include environmental advocacies, fossil fuel advocacies, nuclear advocacies, financial traders, independent power producers, demand response aggregators, marketers, large and small customer groups, unregulated affiliates of IOUs that are not utilities, and any other MMS that is not an investor-owned or publicly-owned utility. This sector is not likely to have many common interests, whereas the IOU and PP sectors might have much greater consensus of interests, depending upon the issue at hand. This imbalance between the sectors could effectively mute the Independent sector. One possible solution would be to broaden the number of sectors by further subdividing the Independent sector, however we are not proposing that at this time. We will take the approach of waiting to see what results from actual experience with the three-sector voting structure. Should future experience show that the Independent sector is being effectively shut out of MPEC decisions due to inability to reach consensus, we would view this as a reason to initiate a governance review process under section 4.1 of the governance proposal.
2. The vote of each sector is based on the number of members who vote, not the number of members in the sector. This raises at least the theoretical possibility that if a significant number of members in a sector do not have a vested interest in a particular issue, a few members of a sector who are most vested in the issue could determine the vote of the sector. A possible solution would be to establish quorum rules for sector voting. We are raising this concern as a possibility, not a likelihood, and therefore take the approach of seeing how this dynamic plays out in actual experience. As above, unintended or undesirable experience could be a reason to initiate a governance review process under section 4.1 of the governance proposal.
3. We note that the MPEC rules for affiliate voting are newly emerging in this draft. As far as we can discern, the only requirement that affiliates vote collectively as a single member is with respect to electing or removing members of the MIP (Section 3.2.2.2, Item 3, p.9). Our brief review of other wholesale markets/RTO's shows that most require collective voting of affiliates in much broader circumstances. We anticipate this issue will require continued discussion as the proposal is further elaborated and the tariff developed. Stakeholder reaction to the MPEC voting structure overall will be an important precursor to understanding how affiliate voting might operate. We look forward to participating in the dialogue when it is ripe.

M+ Independent Panel (MIP) Nominating Committee

It is proposed that the MIP Nominating Committee will be composed of one MPEC member for each of eleven sectors as opposed to the version 2 proposal which had 10 sectors. The additional sector in version 3 is created by adding two new sectors, (i) Residential and Small Commercial customers and (ii) Industrial and Large Commercial customers, and eliminating one sector, Trade Associations.

Presumably, then, each MPEC member would be assigned to one of the three sectors for MPEC voting as well as one of the eleven sectors for MIP Nominating Committee purposes. This raises the following questions:

1. Where would a trade association be assigned for MIP Nominating Committee purposes?
2. In many if not most states, the Residential and Small Commercial customers are represented by a state agency, often referred to as the Ratepayer Advocate or an equivalent name. Would SPP make special fee-waiver and MSS agreement arrangements to allow a state agency to become a member of MPEC, as is done in ISO-NE for example?

There is a wide variation between MPEC sectors and MIP Nominating Committee sectors that is hard to reconcile: eight of the eleven sectors in the MIP Nominating Committee are lumped together as the Independent sector for MPEC voting. We would agree that too many sectors for MPEC voting, especially with a 67% threshold, might make it too difficult for the MPEC to move initiatives forward. However, a reasonable number of voting sectors for MPEC might be more than three. As we noted in our earlier comments, we will take a wait-and-see approach with this concern.

Markets+ Independent Panel (MIP)

We appreciate the clarified scope of authority delegated to the MIP, the description of how MIP decisions will be acted on and the additional details regarding SPP Board of Directors review of MIP decisions. Per our comments dated July 15, 2022, we continue to consider the MIP's charter and decision standard to be important element of good governance. A statement on what the MIP should be aiming to achieve may further clarify the MIP's role. Such a mission statement could socialize the shared goals of Markets+ participants for the market and governance of the market. SPP might consider language that parallels governing statutes for energy regulators in many jurisdictions. For example: ***The MIP shall promote, protect and expand the success of Markets+ for the benefit of participants and customers as a whole by helping to control costs, protecting the market, its participants, and consumers against the exercise of market power or manipulation, and promoting just and reasonable rates, terms and conditions***.

Markets+ State Committee (MSC)

The proposal recommends that each state with a market participant that has generation or load in the state have one representative on the MSC which would be appointed by the public utility commission. We recommend that the MSC also include three advisory (i.e., non-voting) members representing consumer-owned utilities, publicly-owned utilities, and power marketing agencies, respectively. This is a practice adopted recently by the EIM.

Staying Engaged

The Draft Service Offering Timeline and Budget states that the next phase will be approximately 21 months in duration leading up to the FERC filing. We understand this phase will be funded by potential Markets+ participant organizations. The decision-making process during this development phase and prior to seating the MIP is unclear. We would like to better understand the process by which non-participant organizations, like the State PUC MOU Group, can remain engaged in the Markets+ development process through the development of the FERC filing. Particularly, we wonder whether there will continue to be open meetings of stakeholders and opportunities to see and comment on proposed drafts of the tariff as they evolve over the next 21 months.

Signatories

Honorable Eric Blank, Chair, Colorado Public Utility Commission

Honorable Tammy Cordova, Commissioner, Nevada Public Utility Commission

Honorable Megan Decker, Chair, Oregon Public Utility Commission

Honorable Cynthia Hall, Vice-Chair, New Mexico Public Regulation Commission

Honorable C. J. Manthe, Commissioner, Nevada Public Utility Commission

Honorable Ann Rendahl, Commissioner, Washington Utilities and Transportation Commission

Honorable Letha Tawney, Commissioner, Oregon Public Utility Commission

Honorable Mark Thompson, Commissioner, Oregon Public Utility Commission

Honorable Hayley Williamson, Chair, Nevada Public Utility Commission

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

October 28, 2022

In reply refer to: BTO, Market Initiatives

To: Southwest Power Pool - Markets +

Re: SPP Markets+ September 30 2022 Market Design and Transmission Availability

Bonneville Power Administration (Bonneville) is a federal power marketing administration within the U.S. Department of Energy that markets electric power from 31 federal hydroelectric projects and some non-federal projects in the Pacific Northwest with a nameplate capacity of 22,500 MW. Bonneville currently supplies 30 percent of the power consumed in the Northwest and has loads located in 8 external Balancing Authorities. Bonneville operates 15,000 miles of high voltage transmission that interconnects most Northwest transmission systems with Canada and California. Bonneville has a statutory obligation to serve Northwest municipalities, public utility districts, cooperatives and other regional entities prior to selling power out of the region. Many of these municipalities, public utility districts and cooperatives are located in our BAA while a few are in an adjacent BAAs that are also evaluating organized market opportunities. Therefore, even if Bonneville chooses to join Markets+, many loads which Bonneville serves will potentially be in a different day ahead market or no day ahead market at all.

Like many stakeholders in the Western Interconnection, Bonneville is keenly interested in the evolution, development and operation of organized markets. We are engaged in all day-ahead market initiatives being proposed in the Western Interconnection. In August 2022, Bonneville shared with SPP and our stakeholders our intent to fund phase one of Markets+ design development. Phase one offers Bonneville, and other stakeholders, a critical opportunity to help design a successful market framework. As such, please find below our thoughts and comments on the September 30th Market design document.

Governance

Bonneville generally supports the governance proposal and appreciates all the hard work that has gone in to development thus far. Bonneville has the following clarifications, questions, and suggestions to improve on the draft proposal to best serve all participants going forward:

As an overarching issue it is not clear to Bonneville when the Markets+ governance structure will be put in place. Section 3.3.1.4 refers to Markets+ Executive Committee (MPEC) members being assigned to a voting group upon signing a participant agreement, or stakeholders that pay their annual fee. This indicates that the governance structure will not be put in place until sometime after the phase one process or tariff and protocols development. However, the proposal does not outline when the governance will be put in place. Bonneville agrees with suggestions that establishing the governance structure early in phase one would provide a useful structure for participants and stakeholders to develop the tariff and protocols.

Bonneville believes that the governance structure is one of the strongest assets of the Markets+ proposal, and that establishing the governance structure early in phase one would demonstrate to all prospective participants and stakeholders that Markets+ is founded on an open process that is superior to other potential day-ahead market opportunities. Having the governance structure in place—with the support of the MPEC to provide direction, and working groups and task forces to develop the tariff and protocols—will streamline the process and create a sense of ownership for participants and stakeholders.

Bonneville proposes that MPEC members could be seated when they pay their share of the cost of phase one, and stakeholders would be able to pay their annual fee or seek a waiver. It will take a few months to select and seat the Markets+ Independent Panel (MIP), but the MIP should be in place by the time the tariff is developed and protocols need to be approved. Bonneville recognizes the cost of seating the MIP during phase one may not have been included in the cost estimate provided in the proposal, but the incremental cost spread across all participants is worth the value the MIP would provide. Having the governance structure in place during this development stage will also give participants and stakeholders the opportunity to put into practice their role in the governance process.

Please explain in the final product offering when the governance structure will be put in place, and how SPP anticipates the phase one process will be organized. If SPP intends to delay establishing the governance structure, please explain why the governance structure would be inadequate or inappropriate early in phase one.

<u>Section 3.1.1 and 3.2.1 SPP Board responsibilities and the role of the MIP</u>

Section 3.1.1 describes the types of issues that will need to be elevated to the SPP Board, but it does not speak to the process for developing these issues before they go to the SPP Board. Item 1.b. refers to issues that were previously raised to the

MIP, but none of the other issues listed refer to any preceding process. Bonneville suggests adding a clarification in the proposal that, before the SPP Board's review, all issues listed in 3.1.1 sub-categories 1 and 2 should go through the full process described in the proposal. That is, details should be developed by a working group, the MPEC should review and make a recommendation to the MIP, and the MIP should vote and pass this on to the SPP Board as a recommendation. For purposes of developing the Markets+ annual budget a work group should be formed that works closely with SPP staff on the inputs for draft budget that would go to the MPEC and then to the MIP, which would give an advisory opinion to the SPP Board. This clarification would provide meaning to the statement in the proposal "[t]he board will give significant recognition and deference to the Markets+ Independent Panel (MIP) decision-making role."

The one exception to the process clarification is 1.c. Legal and/or litigation disputes or actions involving SPP or the implementation of Markets+. By their nature, these issues would not flow through the normal process. For this exception, the SPP Board should consult with the MIP to gain their perspective and to fully understand the background of the legal dispute.

A reference back to the clarification described above should be added to the first paragraph of section 3.2.1 MIP Purpose and Scope of Activities. This will clarify that the MIP responsibilities include making recommendations to the SPP Board on the issues listed in 3.1.1.

<u>Section 3.2.3.3 MIP Election Process</u>

Bonneville proposes to add to section 3.2.3.3 additional instruction for identifying qualified MIP candidates. This would add the use of a national executive search firm to develop a wider pool of qualified candidates from across the country with diverse experience. Bonneville has seen the value added by an executive search firm in other contexts.

The additional provision would be added to paragraph 1: "The process will include obtaining the services of an executive search firm to conduct a nationwide search for qualified candidates. The firm will screen potential candidates from the nationwide search and those proposed by market participants and stakeholders. The screening is to provide an initial assessment of candidate qualifications and/or potential conflicts."

<u>Section 3.3.1.4 MPEC Voting Structure</u>

As mentioned above, section 3.2.1.4 refers to MPEC members being assigned to a voting group upon signing a participant agreement, or stakeholders paying their annual fee. As discussed, Bonneville believes the MPEC should be in place much earlier in the process, but there is another issue regarding the timing of the transition to starting operations.

Most likely, all potential market participants will not be ready to join Markets+ at the same time. Some will take longer than others to secure internal and external approvals to join, and some may face delays in completing system upgrades to interact with the market. For most, this delay in being able to sign a participant agreement will probably be no more than a year or two, but these entities will still have a significant interest in establishing, and making changes to, the Markets+ tariff or protocols. How will entities that intend to join later participate in the governance structure if getting a seat on the MPEC depends on signing a participation agreement? SPP should consider allowing these prospective participants to sign up as a stakeholder, or to pay some amount greater than a stakeholder to be assigned to the MPEC group they would qualify for when they do fully join the market.

Section 3.3.2.3 MSC Support and Funding

Bonneville appreciates the response in this revised proposal to our comments about the process for confirming the annual budgets for the MSC. The proposal adds Bonneville's suggestion that the MIP shall seek comment on the proposed budget from the MPEC. However, the proposal remains silent about guidance in the event that there is disagreement between MPEC or the MIP and the MSC on the proposed budget.

Bonneville suggests that in the event of an objection from either the MPEC or the MIP, the proposed budget be returned to the MSC to consider revisions and resubmit a proposed annual budget. The MIP should request specific revisions by the MSC to the proposed budget. The MSC may respond with a revised budget or renew its recommendation for its original budget proposal. The MIP will then vote to accept the MSC budget or prescribe specific revisions for a final annual budget.

3.4 Other Committees and Stakeholder Groups

As discussed above, working groups and task forces should be used to develop the tariff, protocols, and business practices in phase one. If the governance structure for MPEC is not in place, please explain how these working groups and task forces will be formed and directed.

3.4.1 and 3.4.2 Working Groups and Task Forces

Under Section 3.4.1, the *MPEC* may establish working groups. Under Section 3.4.2, the MPEC *Chair* may create task forces. However, both sections refer to the voting structure under 3.3.1.4. Please confirm our understanding that the MPEC may create working groups and task forces, following the voting structure of 3.3.1.4. References to MPEC *Chair* in 3.4.2 should be removed to avoid confusion. The process for appointing task force chairs should be moved to Section 3.4.2.1 to correspond to 3.4.1.1.

As a general matter, Bonneville understands the difference between working groups and task forces being that the former are specifically identified in the bylaws and do not have a time limitation. As such, Sections 3.4.1 and 3.4.2 might be combined to avoid repetition or ambiguity where slightly different language is used. If there are other important differences between the two sections, please explain why those differences are necessary.

3.4.1.1 and 3.4.2.1 Working Group and Task Force Composition and Terms

Bonneville appreciates the proposal moving away from giving the MPEC Chair unilateral appointment power. However, Bonneville continues to have concerns that the proposal's process for selecting working group and task force representatives would be unnecessarily contentious and would not establish a foundation for collaborative development of market improvements. Also, separate processes for selecting representatives for working groups as opposed to task forces seems to add unnecessary complexity.

Under Section 3.4.1.1, nominations would be solicited (presumably by the SPP Staff Secretary as in 3.4.2.1), the MPEC Chair would make recommendations to the MPEC, and the MPEC would approve representatives. Under Section 3.4.2.1, the SPP Staff Secretary would solicit nominations, and the MPEC Chair would unilaterally appoint representatives. The value of the MPEC Chair balancing a slate of expertise and diversity is outweighed by the risk of excluding important perspectives, and opens up potential accusations that the working group or task force is being staffed to encourage a predetermined outcome.

Instead, Bonneville proposes to build from the more inclusive concept of the sectors used in the MIP Nominating Committee. Each sector may nominate a representative to each working group and task force. Depending on the issue, a sector may choose to not nominate any representative. To ensure greater regional diversity, SPP could consider allowing sectors to have multiple representatives, such as an IOU north and south representative. While Bonneville would prefer that the sector nominees automatically be appointed, Bonneville could support having the sector nominees subject to approval by the MPEC or MIP.

Importantly, Bonneville wants to confirm its understanding that any Markets+ Market Participant (MMP) or Markets+ Market Stakeholder (MMS) can participate and offer perspectives in working group and task force open meetings. That is, the processes in Sections 3.4.1.1 and 3.4.2.1 are concerned only with appointing the representatives who will have Section 3.4.1.4 voting rights. Our understanding is that any MMP or MMS could contribute within open meetings, and—under Section 3.7—could appeal working group and task force recommendations to the MPEC and submit alternative recommendations.

Regarding chairs for working groups and task forces, Bonneville does not oppose having the MPEC or MIP designate a sector-nominated representative as chair. It is not clear why different processes are needed in 3.4.1.1 and 3.4.2. We would also support allowing the working groups and task forces to self-designate their own chair from among the representatives.

Finally, Section 3.4.2.1 states, "Except for any *full representation group,* an appointment to a Task Force is for an individual, not a corporate entity." The italicized phrase does not appear in 3.4.1.1 or elsewhere. Please clarify what a "full representation group" is, why they would not also be appointed as an individual, and why the exception does not apply to working groups.

3.4.1.3 and 3.4.2.3 Working Group and Task Force Vacancies

Under these sections, vacancies would be filled on an interim basis by appointment of the MPEC Chair. Consistent with Bonneville's proposal for sector-based appointments, Bonneville proposes instead allowing sectors to select their replacements. This could be an official appointment, or on an interim basis until approved by the MPEC or MIP. The process should be the same under Sections 3.4.1.3 and 3.4.2.3.

Section 3.5 SPP Staff Independence and Support

Statements on staff support are referred to throughout the proposal in individual sections. Bonneville recommends consolidating those recommendations in section 3.7 to address proposed staffing support for the MIP, MPEC, MSC, working groups, and task forces. As the proposal progresses, estimates of FTE would be helpful to understand the level of support that will be available to all these groups.

Section 3.6 Attendance, Quorum, and Proxy

Section 3.6 addresses attendance, quorum and proxy for some of the groups. It should also include a statement that MIP members must be present to vote and cannot use a proxy. Although this requirement is addressed in section 3.2.5, it should also be addressed in 3.6 where the quorum rules for the MIP are addressed. Bonneville supports the proposed proxy approach for the MPEC, committees and working groups.

Section 3.7 Appeals to the MPEC and MIP

Section 3.7 states the MIP may take any action it deems necessary to address an appeal, including affirming, reversing, or remanding. This section should similarly describe the actions available to the MPEC in response to an appeal.

For all appeals to the MPEC or MIP, a timeline with specific steps and actions should be defined and included in the governance proposal to address the actions of the MPEC, the MIP and the entity making the appeal. The MPEC, MIP and submitting entity should be held to clear timelines for each step in the appeal process. The timeline and steps should make it clear that the appeal must be addressed by the MPEC and/or MIP prior to any further action being taken on the issue being appealed.

Section 4.1 Governance Review

Bonneville appreciates the proposal including a sector-based governance review working group appointed by the MIP.

The proposal calls for an automatic review of the governance structure three years after the Markets+ market launch. If the market structure is put in place during phase 1, Bonneville suggests that the automatic review take place three years after the MIP is initially seated. This will ensure that the governance review takes place in a timeframe near the transition from formation to market launch.

Market Design

The market design elements and operational framework are critical to the establishment and success of an organized market. Bonneville is generally supportive of the day-ahead and real-time energy and flexibility reserves market design that SPP has proposed but we recognize that further developments must take place during phase one. We appreciate that SPP has identified the importance of engaging stakeholders in continued conversations around the market design. As an interested stakeholder, we intend to remain fully engaged and participate in the development effort throughout phase one.

There are several aspects of the market design in which Bonneville would like to provide comments.

Day-ahead Market structure

Bonneville supports SPP's proposed approach to exclude operating reserves (regulation-up service, regulation-down service, spinning reserves and supplemental reserves) from the proposed market design. Bonneville is in agreement that these services should continue to be managed by individual BAAs under existing paradigms. It should also be noted that many entities (including Bonneville) manage contingencies through participation in the Western Power Pool's (WPP) Reserve Sharing group. Bonneville encourages SPP to engage with WPP to ensure that the coordination around the deployment and delivery of contingency reserves is respected by the Market Operator and will not be impacted by market dispatches. In our view, this will require coordination and alignment between the Market Operator, Reserve Sharing Group, and respective BAAs.

SPP posits two options around the structure of the day-ahead market. Bonneville encourages SPP to engage stakeholders in robust conversation around these options. Bonneville is specifically interested in a better understanding of "option two", a multistage process where physical resources are committed ahead of the voluntary financial market. Bonneville believes this option may result in more appropriate price formation. We are interested in engaging in further conversation in order to ensure we thoroughly understand all details (including strengths and weaknesses) associated with both options.

Resource Registration

SPP proposes to require the registration of all resources inside a participating BAA but later in the document discusses the ability to group hydro assets together. Bonneville believes it is SPP's intent to allow the aggregated modeling of hydro resources but we seek clarification between the resource registration requirement and the proposed aggregated hydro model.

Registration Requirements

SPP proposes to require all transmission assets greater than a de-minimis threshold (e.g., 100KW) to register with the market. We are unsure that the referenced threshold of 100KW is the appropriate cutoff. Bonneville suggests that participants should register assets based on what is already identified in the network model and/or what is already identified in BAA large and small generator interconnection agreements. We look forward to further discussion with SPP and other stakeholders on what is the appropriate registration threshold.

Market Storage Resource

Bonneville requests clarification on whether pumped storage hydro resources can be considered electric storage resources (ESRs). Bonneville suggests that pumped storage hydro should be eligible for ESR classification because it is a proven and reliable resource capable of receiving electric energy and storing it for future injection of electric energy to the grid.

Grouped hydro resources

It is critical to Bonneville that the market design incorporate and allow for grouped hydro resources. In our participation today in a Real Time imbalance market, we have aggregated ten of our large hydro generation facilities into three distinct groups based on electric and hydrologic nexus and environment, fish and wildlife responsibilities. Bonneville appreciates SPP's willingness to open this topic for further stakeholder discussion. We anticipate being heavily engaged in the future conversations around grouped hydro participation in the day-ahead market in order to ensure Bonneville's participation is feasible.

Price Formation

Bonneville appreciates SPP's willingness to begin to address both fast start pricing and scarcity pricing. Both of these topics are important to many stakeholders and may affect stakeholder's willingness to participate in the market.

Minimizing out of market actions is an important topic to Bonneville and other stakeholders. We look forward to further discussion on price formation during phase one.

Reliability Unit Commitment (RUC)

In the proposal SPP suggests continuously validating unit commitment decisions between the posting of day-ahead market results and real time. Bonneville finds this an interesting approach but feels that much greater detail needs to be shared with stakeholders in order to appropriately assess the proposed approach. In particular, Bonneville is keen to understand how SPP may approach this "Rolling RUC" process in light of both transmission and generation capacity. Bonneville would like SPP to explain what transmission and generation capacity is intended to be available for the "Rolling RUC" process. Bonneville supports SPP's decision to hold further discussions with stakeholders and encourages SPP to provide detailed examples to stakeholders during conversations in phase one.

Congestion Rent Allocation

SPP proposes to issue congestion rents to the Transmission Contract Holder for affected transmission reservations. Bonneville urges SPP to consider circumstances where congestion rent may be paid to the Balancing Authority, Transmission Service Provider or a scheduling agent instead of the reservation holder. Bonneville believes it would be helpful to walk through examples of congestion rents that are paid on a reservation, and a redirected reservation to refine the proposal.

Physical Sufficiency

Physical Sufficiency is an essential component of operating a market that is both reliable and provides maximum benefits to participants. Bonneville strongly supports the inclusion of a common resource adequacy standard and associated must-offer obligation, and supports the use of the WPP WRAP as the common standard, as many of the potential Markets+ participants are already committed to or considering WRAP membership. Further, Bonneville supports applying an equivalent standard to any market participants not formally enrolled in the chosen RA program. A common resource adequacy standard will ensure participants start from a level playing field, bolster the reliability of the footprint while achieving a diversity benefit among participants, and simplify the Markets+ program.

Bonneville recognizes that there are a number of details for stakeholders to work through to appropriately integrate an RA program with the Markets+ design in order to provide maximum benefit to participants. For instance, with WRAP, stakeholders will need to consider the best approach to the non-binding months of the program; WRAP and Markets+ stakeholders will need to design uncertainty methodologies to reflect the differences in timing of the two programs in the operational timeframe; market design will have to account for WRAP members outside of the market footprint. Understanding overlapping timelines and working through day-in-the-life examples will be essential to ensuring a robust design. With careful consideration and collaboration, Bonneville is confident stakeholders can design an efficient, beneficial process during the next phase of development.

External Resource Participation

Bonneville believes that allowing known external resources with contractual relationships with a Markets+ participant (or with LSEs within the SPP participant BAA) to self-schedule and economically bid into Markets+ is absolutely necessary and must be a day one feature of the market. SPP proposes to limit external participation to pseudo tied resources. Bonneville believes that all entities evaluating market opportunities are unlikely to join at once. We suggest that the market design be robust enough to allow for external resources to bid into the market whether they are within a participating BAA or not. We recommend against severely limiting external resource participation by requiring pseudo ties.

Market Transmission Service (MTS)

Bonneville requests clarification on several aspects of the MTS proposal:

1. Please confirm that SPP intends to utilize unused Conditional Firm transmission from a participating BAA in the market optimization solution.
2. Given FERC Order 890 characterization of conditional firm transmission as a category of firm transmission, SPP must provide congestion rents for Transmission Contract Holders with firm reservations, including Conditional Firm reservations that are firm through the operational timeframe on the portion of the system that is congested. Bonneville recognizes that further development of congestion rent allocation proposals for conditional firm will require coordination between Transmission Providers and SPP in a task force or another forum to determine when congestion rents may be limited because of the conditions that apply to conditional firm service.
3. Bonneville generally agrees that Markets+ must have a mechanism to recover transmission costs that does not result in cost shifts. Bonneville suggests that each BAA and Transmission Provider must retain the ability to set rates, with consideration of appropriate inputs from market participation. Bonneville currently sets rates every two years based on cost projections. Bonneville must maintain the ability to set our own revenue requirement to ensure repayment of the federal investment and appropriate rate design as required under the Northwest Power Act.

4. Bonneville requests further discussion on how the market solution will account for imports, wheel-throughs, and exports to non-participating BAAs. Bonneville believes that “seams” between markets will be an increasingly important topic as all day-ahead market initiatives continue to advance and mature. Seams issues may include differences in transmission operating rules, power market design, scheduling practices, settlement practices, and resource adequacy programs, etc. Bonneville suggests that SPP and other market initiatives be open to discussions to identify and address “seams” issues as soon as practical.

Convergence Bidding

Bonneville does not oppose the delaying of convergence bidding to allow the market to mature and allow participants to gain comfort and proficiency in market participation.

Greenhouse Gas

Bonneville appreciates SPP’s inclusion of GHG reporting and the cost of GHG programs in the market design. This is an important issue to Bonneville given that over 63 percent of Bonneville’s firm power sales to its preference customers are made to utilities in the state of Washington, and Bonneville sales to Washington utilities account for about 50 percent of the electricity consumed in the state. Bonneville appreciates SPP’s proposal to use a zonal approach, which Bonneville believes provides a reasonable basis for GHG accounting for the market. As SPP further develops this approach in phase one, Bonneville encourages SPP to work closely with state regulators in Washington, including the Washington Department of Ecology, Washington Utilities and Transportation Commission, and Washington Department of Commerce. Bonneville looks forward to engaging with SPP on the market design for GHG accounting to ensure the design is compatible with Bonneville’s statutory requirement to make system sales and some of the unique Bonneville-related provisions in Washington’s cap-and-invest program.

Closing Remarks

Bonneville would like to acknowledge and thank SPP for all the work that has already gone in to development of the Markets+ day-ahead proposal. It is clear to Bonneville that phase one of Markets+ will be critical for stakeholders and SPP to engage in thorough and transparent discussions on many market details. As such, Bonneville requests that SPP prepare and share a list of topics in which SPP anticipates further discussion with stakeholders. This will aid stakeholders in understanding the amount of expected participation and allow stakeholders an opportunity to ensure the appropriate subject matter experts are able to participate in the discussions. Lastly, as SPP prepares to embark on phase one, we encourage the development of detailed examples (where possible) on topics for use in workshops and discussions with stakeholders.

PUGET SOUND ENERGY

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
PSE.com

October 28, 2022

Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223-4936

Re: Southwest Power Pool Market Design Draft - Comments of Puget Sound Energy

SPP Staff:

On September 30, 2022, the Southwest Power Pool ("SPP") issued its Markets + Draft Service Offering outlining its current proposal for the Markets+ market design. The Draft Service Offering lays out the various market roles and proposes treatment for interchange transactions, transmission service, congestion rent, price formation, unit commitment, market mitigation, and settlements. It also proposes a method for attributing and settling greenhouse gas costs to participants. Puget Sound Energy ("PSE") respectfully submits the attached comments in response to that proposal.

Puget Sound Energy supports many conceptual aspects of SPP's proposal, namely the intention to integrate the SPP market with the Western Resource Adequacy Program, the prioritization of reliability within the Markets+ footprint over exports to other regions, and a GHG accounting framework that gives Washington utilities greater control to direct the use of their customers' clean resources for compliance with state laws and regulations. PSE suggests additional workshops within the Markets+ Design teams to work out the details needed in the next iteration of the design draft.

PSE appreciates this opportunity to comment on the proposal and looks forward to additional development of the concepts put forward by SPP in this market design.

Sincerely,

Phil Haines
Director, Energy Supply Management
Puget Sound Energy

Governance

The structure of the proposed Markets+ governance framework is likely to have a profound influence on the capacity and ability of the regional market footprint to implement change and support the diverse economic and regulatory needs and environmental goals of its collective members. SPP's proposed framework instills PSE with confidence that all market participants will be fairly and well represented through the Markets+ Participants Executive Committee (MPEC). PSE appreciates the level of independence and autonomy within both the Markets+ Independent Panel (MIP) and the Board of Directors. PSE is supportive of this framework with additional comments and suggested revisions below:

Section 3.2.1 - Appeals process for MIP action/inaction

"Appeals: […] should the SPP board determine there is not sufficient consensus supporting the MIP's decision, and provided time allows, the SPP board of directors may remand the issue to the MIP and/or the appropriate Markets+ working group for further consideration. […]"

- In the case where a MIP member requests that the Board review a MIP action, the charter should define a timeline in which an appeal may be submitted. For example, an appeal must happen no more than 15 days following MIP action.
- In the case of inaction, the charter should define a timeline in which an appeal must be submitted and completed. For example, if the MIP does not take action on an item brought before it within 45 days, a MIP member may request a Board review.
- The secondary determination of 'sufficient consensus' by the board needs additional consideration and discussion regarding the threshold and criteria for determining consensus. This objective criteria is necessary to ensure member confidence in the MIP's authority.

Section 3.2.1 (3) - Authority of MIP

"In carrying out its purpose, the MIP will: Consider, approve or reject market rules if such rules solely apply to the administration of the Markets+ market and have no application to the SPP Integrated Marketplace or any other service provided by SPP."

- This section lacks objective criteria and may lead to confusion or jurisdictional questions about what lies within the authority of the MIP. PSE recommends the consideration of some form of threshold test that outlines criteria for determining whether an issue applies solely to the administration of the Markets+ market. Additionally, SPP should carefully consider the process for how that determination is made, and by whom.

Section 3.2.3.3 (4) - Additional MIP Nominations

"Any additional nominee(s) may be added to the ballot specifying the nominee(s) to a single seat or multiple seats if a petition is received by the staff secretary at least 15 calendar days before […]"

- Under subsection (2), the staff secretary is required to deliver the ballot to participants and stakeholders at least 30 calendar days prior to the Forum, but additional nominees can be added within a 15-day window of the forum.

- PSE requests that the following clarifying change be made: The staff secretary will prepare and deliver a new ballot, if new nominees are added, no later than ten calendar days before the Markets+ Market Participants and Markets+ Market Stakeholders Forum.

Market Design

PSE is supportive of further exploration and development of option 2, in which units are committed up front, the financial market is segregated and is driven by the forecasted expectations for real time. PSE believes that separation of these processes will drive reliability and efficiency by facilitating the creation of a day-ahead schedule that more closely resembles the real-time schedule. Segmentation of the unit commitment process from the day ahead clearing process in the integrated forward market (IFM) could potentially benefit the footprint by minimizing total production costs, facilitating VER penetration and reducing inefficiencies. For this concept to work, it will be particularly important to have further discussion on how the pricing run would operate.

PSE supports aspects of the resource participation model such as registering resources on a nodal basis, and the ability to register resources as either an individual, or an aggregate, which allows flexibility on how these resources are treated.

Regarding metering requirements, PSE agrees that the size requirement for behind-the-meter generation should be between five to ten MW. PSE requests clarification on whether participants would elect their own size requirement within the given five to ten MW range or if there is a standard requirement among all participants.

While flexibility products have not been fully addressed, PSE has questions about how these flexibility reserves will be procured by the market. Further discussion is needed on whether participants will elect and bid their resources for flexibility reserves and whether flexibility reserves will be co-optimized with day-ahead energy schedules or optimized sequentially. Additional consideration is needed regarding a penalty framework for participants that fail to deliver flexibility reserves in real-time.

Transmission

It is integral to a regional market design to have balance between centralizing transmission to maximize diversity and market benefits while still respecting the existing rights of Transmission Service Providers. PSE supports an all-in transmission model with enumerated Service Flow Constraints that preserve transmission rights. PSE requests further discussion regarding the criteria, limits, timing, and other design issues for transmission that is held back for reliability and external market participants. PSE notes that regulated Transmission Service Providers use other Priority 6 products other than Conditional Firm and wonders if these products should also be included for reliability purposes.

Additionally, PSE requests clarification on the role of the Transmission Service Provider while the day-ahead market processes run, and the tagging of dispatchable interchange schedules. With respect to the day-ahead market process, SPP should clarify what entity will be monitoring any transmission sales that occur during day-ahead processing and whether those sales will be prevented during that window.

With respect to dispatchable interchange schedules, SPP says in its Draft Service Offering that any changes made to e-tags after day-ahead market clearing will be settled as deviations from the day-ahead market. But SPP also states it will provide participants with the megawatts of dispatchable schedules cleared in the day-ahead market and may require participants to update their tags with the day-ahead cleared megawatts. SPP should clarify which changes to e-tags are considered deviations from the day-ahead market and whether megawatt quantities amended after day-ahead clearing carry through to the fixed real-time schedule.

Further discussion is also needed on the following topics:

- The function of Market Transmission Service billing determinants
- The parameters of Markets+ information exchange related to sensitive transmission data of the participating TSPs
- Notification of transmission redirects when Market Transmission Service handles alternative use of the system

PSE requests that additional consideration be given to the calculation of a Transmission Provider's annual transmission revenue requirement (for the purpose of determining the qualified recovery amount and qualified revenue ration) to ensure uniformity of methodology across both jurisdictional and non-jurisdictional entities.

Congestion Rent

PSE supports various aspects of the proposed method for allocating congestion rents. This includes distribution on a transmission service request basis (vs. schedule-based), allocation based on prevailing flows, and limitation of the hourly amount available for allocation to the amount that has been collected. These elements reduce the reliance on out-of-market uplift payments.

PSE appreciates the simplicity of the proposed calculation/allocation model.

Resource Adequacy

PSE agrees with the proposal to require participants to participate in and comply with an existing resource adequacy program such as the Western Resource Adequacy Program (WRAP), or to meet an equivalent standard. This prerequisite in conjunction with a must offer obligation is likely to instill market participants with confidence that sufficient capacity has been procured.

The option of requiring resources with a capacity obligation or holdback requirement in a resource adequacy program to be available for market commitment and dispatch in the day-ahead market is reasonable if coupled with an appropriate pricing incentive mechanism.

Market Convergence and Virtual Bidding

While convergence bidding is a key component of an organized market for establishing efficient prices, creating liquidity and addressing supply deficits, PSE recommends that any form of virtual or convergence bidding should be delayed for at least one year after market implementation as participants observe and evaluate the operation of the market and the utilization of their resources.

Market Settlements

PSE is supportive of the proposed payments, settlements, and resettlements design and the associated timelines. More information is necessary on the mechanics underpinning the calculation of locational marginal prices. SPP should also consider the process for handling pricing discrepancies that are discovered.

PSE supports the marginal loss concept. PSE would be concerned about how marginal losses are accounted for in the event of unit loss, transmission loss, or congestion. If the above considerations are included in the logic, the marginal losses concept seems more efficient.

Implementation Costs and Timeline

PSE requests clarification on the implementation timeline. The draft service offering states 21 months until a tariff filing with the Federal Energy Regulatory Commission. PSE requests details regarding when this 21-month time period begins. If the 21-month period begins after the final service offering, PSE questions whether there is sufficient time for regulatory review and approval before the intended Markets + go-live date.

Greenhouse Gas Accounting

Entities evaluating SPP's Markets + design sit within different jurisdictions and are subject to myriad, and sometimes discordant, laws and regulations regarding their procurement of clean energy and the reduction of emissions. While there is still significant work to be done to develop this proposal, PSE appreciates SPP's efforts to listen to stakeholders and bring forward a framework that attempts to achieve many of the principles outlined by the market participants in the region:

- Addresses various state emissions laws and regulations and supports accounting, reporting and compliance requirements in those states.
- Provides a transparent resource optimization framework that considers the price of GHG emissions.
- Associates the costs of greenhouse gas (GHG) with the resources and parties responsible for those emissions.
- Enables utilities to have greater control to direct the use of their customers' clean resources for compliance.
- Minimizes impacts of GHG policies on jurisdictions without GHG policies.

PSE looks forward to further discussion on SPP's zonal approach to GHG accounting and conceptually supports the ability for entities to direct the use of their clean energy, as needed, for compliance, contractual arrangements, and other clean energy goals using GHG pricing, zones, and shadow pricing for transferring different carbon intense resources between zones. PSE appreciates the transparent discussions thus far on the design process and encourages SPP to actively engage with the Washington Department of Ecology and the Washington Utilities and Transportation Commission on this issue. Washington is undergoing rapid transformation of its energy systems through the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA), and other clean energy laws that make it critical for its regulators to be part of shaping this process. Additionally, SPP should be consulting with the California Air

Resources Board with the intent of establishing a market design that will support a potential future linkage between California and Washington.

The comments provided below are based on a combination of SPP's August 26, 2022 Market Design and Transmission Availability Working Draft and the GHG Model Proposal in SPP's August 24, 2022 webinar.

SPP proposes three types of resources that can serve load within a GHG zone: GHG internal resources, specified source imports, and unspecified imports. This proposal does not contain the explicit conditions for specified source imports that are subject to the GHG costs internal to the GHG zone. This list may not be exhaustive, but PSE recommends the conditions include resources pseudo-tied into a balancing authority area wholly located in a GHG zone, resources committed under long-term contracts to serve load within the GHG zone, and portions of the above two resource types that are cost-allocated to serve load in a GHG zone. PSE supports some elements of transmission criteria for qualifying specified source transfers into a GHG zone, but this requires further discussion. PSE supports the additional comments of the Western Power Trading Forum regarding the role of the GHG regulator on the issue of specified import criteria.

PSE agrees the appropriate entity to collect payments associated with unspecified imports should be determined through a stakeholder process to ensure symmetry with state GHG reporting rules establishing compliance obligations and reporting requirements.

There is not currently enough detail in the SPP design draft for PSE to take a position on a GHG "system zone" power balance constraint that must be satisfied before exports are considered, in addition to the larger Markets+ system power balance constraint. Under CETA, it will be important for utilities to ensure their clean energy can be accounted for by Washington customers. But the solution should consider utility operations that at times take advantage of cost-effective market purchases outside its system to reduce net power costs for customers when it is economic to do so. Further work is needed to address how optimization occurs across multiple GHG and non-GHG zones, how transfers between GHG zones are priced, and how GHG revenue is collected and distributed. This work should include the GHG regulators of the GHG zones.

PSE appreciates SPP's consideration of "MW Redesignation Concerns" in its design. This will be a key factor for regulators and policymakers when evaluating the efficacy of state GHG programs, for utilities demonstrating the use of clean energy, and for the market attributing cost-causation in GHG price formation. SPP has begun to capture some of the concerns with accurately representing a baseline in a two-pass solution, which will aid the discussion of a robust design that considers the impacts of emitting and non-emitting resources being incremented to serve marginal load inside and outside a GHG zone, as well as between GHG zones. PSE looks forward to further work on this issue.

October 28, 2022

Idaho Power Comments on Markets+ Draft Service Offering

Introduction

Idaho Power Company appreciates Southwest Power Pool's (SPP) efforts to date on the Markets+ service offering. Idaho Power recognizes the complexity in establishing a western market looking to capture the benefits from a day-ahead centralized optimization while still maintaining separate balancing authorities and Open Access Transmission Tariffs. Idaho Power looks forward to continued stakeholder-involved discussions around the development of such markets.

Idaho Power has an interest in ensuring that as markets continue to develop in the west looking for economic benefits for customers, reliability remains at the front of any design. It is important that native and network load customers of balancing authorities not experience significant cost shifts, especially in transmission, through participation in a new market offering. Idaho Power submits these comments in response to the draft service offering issued by SPP on September 30, 2022.

Day-ahead Market and Physical Resource Commitment

Idaho Power agrees that commitment of physical resources to meet all load is key to reliable market operations. In the draft service offering, two options were offered for possible implementation of the day-ahead market. Option 1 – a voluntary, financial market with financially binding day-ahead positions that include physical instructions for resources to start and stop. Option 2 – a multistage process where a reliability-based, physical resource commitment occurs followed by a purely financial and voluntary day-ahead market. Option 2 appears to be a unique concept not currently seen in RTO/ISO's where a physical Reliability Unit Commitment run is done first, followed by the financially binding energy procurement run. Idaho Power supports SPP's focus on the specific design details to implement option 2 as it appears to ensure enough physical supply is obtained first and then considers economics. However, Idaho Power is interested in the details of exactly how such a design will work. Detailed examples of the settlement of each option would be helpful to ensure that additional costs to customers does not occur under option 2 due to additional capacity payments as opposed to the more traditional option 1.

Joint Operating Units (JOUs)

Idaho Power appreciates SPP considering how JOUs participate in the market. Each JOU is unique and should have more than one option available to owners as to how such units participate in the market. Idaho Power currently has JOUs with different costs than the other owners. Each owner must be able to reflect its costs in the market for its share of the output independent of the other owners to ensure adequate cost recovery.

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Demand Response Resources

Idaho Power has robust demand response programs approved by the Idaho and Oregon Public Utility Commissions. As such, Idaho Power would need to retain the ability to deploy these programs under the program rules, yet still benefit from their use in the market. Idaho Power looks forward to more details on how demand response programs can be utilized in the market and still ensure compliance with the individual demand response program rules.

Variable Energy Resources (VERs)

Idaho Power has a large amount of PURPA VERs, which are not able to be dispatched by the market for economics. Any market design needs to ensure that PURPA resource dispatches remain under the control of the balancing authority and not based on market signals.

Grouped Hydro Model

While Idaho Power appreciates the need to consider resources on a common water system, it will also be important for the integrity of the security-constrained economic dispatch that transmission constraints between such resources are also recognized. When these resources do not inject in the same location (or at the same line/voltage) of a transmission system, the resources should be treated separately when considering market injections.

Idaho Power is heavily reliant on our hydro system for serving load throughout the year, but especially in summer conditions, which coincide with stressed system and scarcity pricing. We want to ensure that our most valuable resource is used in a way to protect our ratepayers, while reliably serving load. Idaho Power looks forward to continued discussion on hydro modeling as utilities with hydro are often situated differently.

Resource Adequacy and WRAP

While looking at a common RA program as a precondition to Markets+ participation is one way to address equitable sufficiency in the market, the market design needs to ensure that participants of the WRAP not in Markets+ still get the benefit of the WRAP program. If a Markets+ participant has a hold back obligation in WRAP, Markets+ must honor that obligation outside the footprint. In addition, as SPP continues to develop Markets+, the design needs to ensure it accommodates WRAP and does not require changes in WRAP for Markets+ participants. WRAP participants may or may not elect to join Markets+. WRAP is an entirely independent program and should be respected as such.

Idaho Power is interested in further discussion around the detailed design of the interaction between the two programs and what time horizon of WRAP showing will be used. Idaho Power is also interested in how the market handles generator resources that may have been in a forward showing, allowing an entity to pass, but due to unexpected outages are not available in the day-ahead market. Idaho Power looks forward to additional discussion and details in this area.

Flow Based Market Options

Idaho Power appreciates the complexity of taking multiple transmission systems and converting them into a flow-based market system. Idaho Power is interested in how Markets+ would interact with transmission systems and balancing authorities not in its market footprint, but that may be in between its market footprint. Markets+ needs to ensure its flow-based model does not create the opportunity for increased unscheduled flow onto a non-Markets+ member's transmission systems. Idaho Power is also interested in how SPP envisions handling market seams that may exist, should that intermediary BA be in a different market footprint than Markets+.

Transmission

As a vertically integrated utility, Idaho Power has different roles to consider when looking at market design. From a transmission service provider's perspective, Idaho Power appreciates the thought that has gone into transmission in the market. Idaho Power agrees that a transmission provider should be compensated for the transmission the market uses and absent a hurdle rate approach (which creates market inefficacies in dispatches and continued pancaked rates), the proposed market transmission service approach appears reasonable for a cost recovery mechanism. Idaho Power is also looking for additional details on any transmission revenue true-up mechanism proposed by SPP in relation to the proposed MTS revenue. While some stakeholders would like to see "free" transmission by the market, as long as each transmission service provider has an OATT, there is no concept for users of the system not paying for that usage. Third-party users of the system must pay their share, and that includes market activity.

Transmission is the key to unlocking benefits in the market. Without the transfer capability between entities, no market flow can occur. As investments in transmission systems are made and increases in transmission revenue requirements are realized, the market should recognize that investment, and allow recovery on the transmission investment from the market as it would historical investment transmission sales. We appreciate SPP's understanding and recognition of this. Idaho Power looks forward to additional details on how the Market Transmission Service mechanism will work to ensure that the market does not create significant transmission cost shifts among customers.

Like many other load serving entities, Idaho Power has made investments in transmission service on third party transmission systems. As a result, transmission customers like Idaho Power need a mechanism to protect and continue to make that investment on those systems. That transmission was procured for the benefit of our customers for serving our own load. Some form of compensation or value should be recognized if the market utilizes that transmission to ensure costs do not increase for load service to our customers, for which that transmission was purchased. SPP's proposal of congestion allocation directly to transmission customers appears to be a reasonable solution, to assign value to that transmission. Idaho Power looks forward to additional details in the next proposal.

Day-Ahead Market Clearing/Bilateral Transactions

Idaho Power understands the need for a submittal by a time certain on day-ahead basis so that the market optimization can be run and provide solutions in a timely manner. However, the deadlines must recognize and accommodate existing required trading and scheduling activities. Idaho Power is concerned about market processes or timelines that may not allow sufficient time for required activities (trading, scheduling, tagging) to occur for those that elect to utilize the bilateral market. The timelines need to be sufficient to allow bilateral activities to occur and to ensure that information provided to the market is accurate and complete. Some processes would need to be thought through on how to efficiently show what transmission is going to be used for bilateral trades, and thus, not optimizable by the market.

Market Settlements

Idaho Power recognizes the need to publish timely settlement statements. However, Idaho Power would recommend that the first meter submission deadline be pushed out to at least OD+5 to give participants additional time to submit accurate meter data. Four calendar days doesn't give proper time to validate data accuracy after weekends and allow for time to make any necessary data corrections prior to the S7 statement.

Idaho Power would also recommend that the S53 statement allow for full dispute of all charges and not just incremental charges. In addition, Idaho Power is concerned with the definition of "material" being set at $2,000 between the S53 and S120 statement. If a market participant disputes charges at the S53, and there is a fix to the system that results in another unintended systemic issue that results in a variance of under $2,000, market participants will be left with no recourse, even though they are able to dispute incremental changes. Idaho Power would ask SPP to consider a process to review system issues brought up by market participants even if they are under the "material" threshold.

Governance

Idaho Power appreciates and supports the governance proposal brought forth by SPP. The proposed independent governance structure is Idaho Power’s preference when moving toward organized markets. Idaho Power encourages SPP to continue to allow broad stakeholder voices to be heard even if those stakeholders are not funding members.

Greenhouse Gas (GHG)

SPP Markets+ is proposing to use a zonal approach for accounting of greenhouse gas market activity. With that approach comes a hurdle rate applied uniformly to out of GHG zone resources regardless of resource type. While Idaho Power appreciates the complexity of accommodating different state greenhouse gas polices in market designs, Idaho Power is concerned that discriminatory dispatch could occur in such a design. For example, clean energy resources located in a non-GHG zone may not be dispatched for a load in the GHG zone simply because the hurdle rate must be overcome. Idaho Power looks forward to additional discussions on how the model may be better able to ensure that clean resources, regardless of location, are dispatched before carbon emitting resources in the footprint. If the goal of GHG policy is to reduce overall carbon emissions, the market design should look for a way to get more resource specific to ensure that clean resources are dispatched regardless of where the resource is located and what load is being served.

Conclusion

Idaho Power appreciates the work that has gone into the draft proposed service offering. There appear to be a lot of details to continue to work out in the next phase and the feasibility and operability of the market will be in those details. Idaho Power believes that any day-ahead market option that develops in the west should ensure that the market design does not degrade reliability, erode transmission revenue, create significant customer cost shifts, should ensure fair and equitable treatment of resources and loads. Day-ahead market options should also accommodate and not disrupt other existing programs and processes. Idaho Power appreciates the ability to comment and participate in continuing discussions around market design elements with other stakeholders as the service offering evolves.

October 28, 2022

To: Southwest Power Pool (SPP):

RE: SPP's Market + Governance Straw Proposal

Tucson Electric Power Company (TEP) would like to thank the SPP team for its efforts in advancing the Markets+ (M+) governance proposal through a collaborate, stakeholder-driven process. TEP is generally supportive of the straw proposal. In addition to the comments, we've provided below, TEP supports the governance comments made by Arizona Public Service, Salt River Project, NV Energy, and Public Service Company of New Mexico.

TEP has several general questions regarding the proposal and would like clarification on the following:

- TEP believes more discussion needs to take place regarding the MPEC voting structure. The final M+ governance MPEC voting proposal will ultimately come down to who will commit to participate in the market as illustrated on slide 11 of the SPP's M+ Development Update slide deck dated September 28, 2022. TEP encourages the SPP to be flexible with the MPEC design considering the MPEC's original intended design was to have a unicameral Balancing Authority (BA) and non-BA voting structure, and now it is proposed to have three equally weighted sectors: Other; Public Power; and Investor-Owned Utilities. TEP suggests that the voting structure be finalized once Market Participants and Stakeholders are identified as we get closer to implementation which would allow a more representative structure based on actual participation.

- Given the diversity in generation resources between the northwest and desert southwest, as well as the northwest being dominated by public power, geographic representation will be important for entities such as TEP. Therefore, TEP believes geographic diversity should be prioritized and included throughout in the M+ governance construct. Geographic diversity (represented by a separate vote for the northwest and the desert southwest) will be critical to the success of any working group, nominating committee, and/or MPEC.

- TEP requests clarification that all elements of M+ would be governed by the MIP, including Resource Adequacy (RA). For example, TEP assumes SPP M+ would use the Western Power Pool Western Resource Adequacy Program (WRAP) for its RA requirements. However, if market conditions necessitate a change to the RA construct, TEP believes that change should ultimately be governed by the MIP.

Additionally, TEP has questions and seeks clarification on the following sections of the governance proposal:

Section 3.2.2 COMPOSITION AND QUALIFICATIONS:

- TEP seeks clarification on whether terms for the MIP can be consecutive, as Section 3.2.2 states that there are no limits on the number of terms an individual may serve. TEP supports revolving terms on the MIP, similar to that provided for the chair of each working group. A revolving membership would allow for new leadership and encourage fresh, innovative ideas to percolate on the MIP.

Section 3.2.3.2.1 Composition of the Nominating Committee:

- TEP encourages a commitment to incorporate geographic diversity into the sectors from which representatives will be chosen for the Nominating Committee. TEP is concerned that the current approach could result in a Nominating Committee that is not geographically balanced. For that reason, TEP supports the following comments from SRP: "In WRAP, some sectors have 2 representatives to represent geographic diversity, such as the RAPC/Participants COU. This sector has SRP as the southwest representative and Chelan PUD as the northwest representative,"

- TEP also requests clarification on how each sector is defined.

Section 3.2.3.2.2 Meetings:

This section states that "Meetings shall be open, however, the MIP Nominating Committee may limit attendance at a meeting by an affirmative vote of MIP Nominating Committee members as necessary to safeguard confidentiality of sensitive information."

- TEP encourages closed meetings of the Nominating Committee until a final draft slate is identified. Due to the sensitive nature during deliberations of candidates, open meetings of the Nominating Committee may prevent open and candid discussion of the candidates.

Section 3.2.3.2.3 Voting Structure for Nominating Committee:

This section states: "Representatives must be participating at a meeting to vote. No votes by proxy are permitted".

- TEP requests clarification of the reasoning for not permitting voting by proxy. TEP encourages SPP to include proxy voting for the Nominating Committee Representatives.

Section 3.3.1.1 Composition of Markets+ Participants Executive Committee (MPEC):

This section states: "Each Markets+ market participant and Markets+ market stakeholder shall appoint one representative to the MPEC".

- TEP requests clarification on the design and composition of the MPEC. TEP encourages further discussion regarding the MPEC voting structure.

Section 3.4.1.4 Voting Structure:

- Given the geographic diversity of the potential M+ footprint, the minority opinion would be important to communicate. Therefore, the governance language should expressly include the ability for any minority opinion to be heard and recorded in the minutes for the working groups and the committees and should be communicated to the MPEC by the Chair of the working group or committee for consideration.

Section 3.4.2 AD HOC Task Forces:

This section states: "A temporary task force may be created by the MPEC chair".

- TEP would like clarification on this and references SRP's comments:

"What is the process for adjourning/dissolving an ad hoc task force? How is it determined that the task force has completed the scope of its work? Is this at the discretion of the MPEC chair, just as the creation of these task forces is? Please add this info."

Section 3.7 Appeals to the MPEC and the MIP:

This section states: "A temporary task force may be created by the MPEC chair".

- TEP would like clarification on this and references SRP's comments:

"Are there default processes or mechanisms for what would happen should the MIP or MPEC not move on an appeal in a timely fashion? Know that the MIP can affirm the (in)action, reverse it, or remand issue back to working groups, but curious if there are contingencies in place should the MIP fail here?"

Section 4.1 Governance Review:

Regarding voting structure changes, this section states: " Findings and a request by the MPEC that participation and voting experiences suggest that changes in voting structures are needed."

- TEP requests clarification whether a majority vote of the MIP would be required to conduct a Governance Review, or would a single entity be able to suggest this voting structure change.

Regarding recommendations for any governance revisions, this section states: "Any modification to Markets+ governance requires a super majority (4/5th Vote) of the MIP".

- TEP suggests that a super majority may not be reasonable and a potential barrier to needed changes to the M+ governance structure. TEP encourages SPP to consider a majority vote (3/5th Vote) of the MIP to move forward with any governance changes.

NIPPC comments on Southwest Power Pool's Draft Proposal for Western Day-Ahead Market and Related Services

The Northwest & Intermountain Power Producers Coalition ("NIPPC") is a membership-based advocacy group representing competitive electricity market participants in the Pacific Northwest and Intermountain region. NIPPC has a diverse membership including independent power producers and developers, electricity service suppliers, transmission companies, marketers, storage providers, and others. NIPPC is committed to fair and open-access transmission service, cost effective power sales, consumer choice in energy supply, and fair, competitive power markets in the Northwest and adjacent markets.

NIPPC supports a competitive electric power supply marketplace in the Pacific Northwest and Intermountain West based on the following principles: adequacy and reliability of electric supply is supported and not compromised; all market and transmission access, pricing, and regulatory structures allow all market participants to operate under fair and equivalent terms and conditions in the regional marketplace; efficient and transparent pricing signals that facilitate investment in electric power supply and transmission infrastructure; and cost effective environmental, safety, and security best practices are put in place and maintained. NIPPC offers Southwest Power Pool (SPP) the following comments on its proposal for Western Day-Ahead market and other services in the hopes future drafts incorporate changes to better align SPP's market offering with NIPPC's principles.

Governance

NIPPC largely supports the proposed governance structure. While NIPPC continues to have questions regarding which sectors individual entities may be eligible to join (see comments below with respect to generators who may be subject to the market without having executed a participation agreement), NIPPC supports the design and voting structure of the Markets+ Participants Executive Committee (MPEC). NIPPC applauds SPP for its diligent consideration of diverse parties' views on the foundational issue of governance. The bulk of NIPPC's comments here focus on other critical market design issues, but without a sound governance structure in the first instance, there will be no market. SPP appears to have digested and addressed this challenging reality that has undermined numerous past efforts at forming organized markets in the Western Interconnection. NIPPC appreciates this fact.

NIPPC specifically supports the three-part sector-based voting structure for the Markets+ Participants Executive Committee (MPEC), including the proposed inclusion of (voting) stakeholders within the "Independents" sector, for the reasons described in detail in prior comments.[1] This proposal is a significant step forward toward a fair, inclusive, and adaptable governance structure for organized market operations in the West, and NIPPC appreciates SPP's willingness to forge this model in response to input from many parties, including NIPPC.

While the draft service offering describes a governance review within three years of the launch of Markets+ that might include potential voting structure changes, NIPPC reiterates its request that the service offering anticipate potential tensions within and

[1] See comments from NIPPC to SPP on the Draft Governance Straw Proposal for Markets+ (July 15, 2022).

among the "Independents" sector, particularly given the proposed inclusion of representatives of voting stakeholders. As NIPPC has previously advocated, a somewhat diverse non-utility sector (comprising, amongst Market Participants, generators, competitive wholesale and retail marketers, competitive transmission providers, and large end-use consumers) within the MPEC is an appropriate starting place for sector-based governance of Markets+. At the same time, experience in other Regional Transmission Organizations has proven that, over time, commercial and policy tensions may be expected to emerge from such a diverse "catch-all" sector. Therefore, the Markets+ service offering should do more to anticipate this eventuality and outline some high-level expectations and procedures by which members of this sector may eventually elect to propose breaking out into discrete smaller sectors for purposes of vote-counting on the MPEC.

NIPPC previously expressed support for providing non-Market Participants, i.e., Markets+ Market Stakeholders (MMS), voting rights within the MPEC, and NIPPC supports SPP's proposal to provide these stakeholders a thus stronger voice in Markets+ governance. While NIPPC continues to believe that the proposed $5,000 participation fee for such stakeholders is an unnecessary barrier and burden on many public interest organizations, if SPP, in practice, waives such fees (a discretionary authority explicitly laid out in the service offering) in order to facilitate greater participation in Markets+ governance, this would be a positive outcome.

NIPPC appreciates other refinements made in the service offering, including specifying that the Markets+ Independent Panel (MIP) and the MPEC will have the authority to select their own chairs and other leadership positions, as well as the broadening of the MIP Nominating Committee to include representatives of large and small end-use consumers.

NIPPC understands that some Market Participants may have concerns that the proposed voting structure of the MPEC could lead to scenarios in which a minority of the load or generation within a given sector may have a controlling vote for that sector. This concern may be most acute within the proposed "Public Power" sector that has a particularly wide divergence of size between its potential members. NIPPC remains open to compelling ways and reasons that any of the three sectors may propose to adjust the basic structure of one-member/one-vote of the MPEC for that sector. At the same time, NIPPC notes that the two utility sectors are characterized by vertical integration in a way that is simply not the case for the "Independents" sector. Given that fundamental difference, a potential refinement or solution for either utility sector on this topic may be appropriate solely for that sector. NIPPC does not propose, nor see a need for, complicating the voting representation itself within the Independents sector.

One issue that NIPPC will closely monitor in future drafts of the SPP proposal is to ensure that any generator or load that is exposed to market settlement has a full opportunity to participate in the governance process (to become a "Markets+ Market Participant" or "MMP"). The draft suggests that a load or generator must execute a Markets+ market participation agreement (in addition to having load or generation in the market) in order to become an MMP and have voting rights.[2] But as further discussed below, some generators or loads may take balancing area services from an MMP but

[2] As defined in the draft:

> **Markets+ Market Participant (MMP):** An entity that *has executed a Markets+ market participant agreement* as part of the Markets+ tariff and contributes generation and/or load to the Markets+ market.

have no interest in participating in the day-ahead market, preferring to rely on transactions in the bilateral market using OATT rights. Accordingly, they would choose not to execute a market participation agreement. But by virtue of the proposed draft market design and depending upon how and when they schedule their transmission service[3], those generators or loads would become subject to market settlements for congestion even without executing a market participation agreement. Generators or loads that are exposed to Markets+ settlement should not be relegated to mere "stakeholder" status simply because they choose not to execute a market participation agreement. NIPPC suggests that any load or generator who is potentially exposed to a Markets+ settlement – either directly or indirectly – should be allowed to participate in Markets+ governance processes, even if they have not executed a market participation agreement. NIPPC requests that SPP further explore the participation model for these entities. NIPPC also reiterates its request for additional clarity about what "contribution" of generation or load means, and how broadly it should be read with respect to eligibility to become a formal Market Participant. In NIPPC's view, it should be read broadly, thereby encompassing owners of independent transmission assets, wholesale marketers, and large end-use consumers.

Market Design – General Comments

NIPPC is supportive, as a general matter, of efforts in the West, including Markets+, to expand regional organized competitive markets. But the evolutionary path of market development that Western transmission providers outside of California have

[3] At p.21, the draft defines market participant as:

> An entity that generates, transmits, distributes, purchases, or sells electricity within, into, out of, or through the transmission system participating in Markets+

without reference to a need for a market participation agreement.

elected over the past decade comes with its share of warts. NIPPC remains open to the proposition that a day-ahead market would at least not worsen the position of competitive generators who operate dispatchable and intermittent resources, developers of new resources, and competitive marketers across the Western Interconnection. But that value proposition is not evident. Across their business lines domestically and internationally, companies in the competitive segment of the power sector have deeper experience with day-ahead markets and regional transmission organizations (RTOs) than any of the transmission providers in the West outside of California. While not panaceas, centralized regional markets and independent system operators unlock the benefits of competition for consumers and overall system efficiency, especially in a context of increasing intermittent generation, better than bilateral markets. But Markets+ (and CAISO's EDAM or any other market that leaves more fundamental transmission reform for another day or year or decade) is neither fish nor fowl: preserving dozens of separate transmission tariffs, balancing authorities, and associated points of friction in a contract-path-based system that will shrink liquidity in the bilateral markets for energy and transmission, without providing independent generators with a system that resolves the challenges of delivering power regionally, upgrading the bulk power system, or interconnecting new projects, and all at a higher cost.

NIPPC therefore has concerns with the overall approach of a (potentially) West-wide day ahead market model that optimizes day-ahead dispatch of resources without being a full RTO. NIPPC cautions that moving away from the existing bilateral market to this proposed non-RTO day-ahead market will inevitably lead to a period of increased uncertainty as buyers and sellers of capacity and energy adapt to the new paradigm. NIPPC suggests that SPP and all Markets+ stakeholders may want to consider once more whether it might be more prudent to pursue a full RTO model. Absent that reconsideration, competitive generators and marketers are left with a perhaps slim hope that the awkward fitting of Markets+ on top of the OATT framework and existing bilateral markets remains supportive of competition and that experience in Markets+ will, in fact, lead transmission providers to becoming comfortable more quickly with deeper reforms that include surrendering some control over how transmission is planned, paid for, and operated.

Market Design -- Transmission

SPP's draft proposal acknowledges the desire to design a market that ensures that transmission customers continue to have confidence in the continuing economic value of their existing transmission rights in the Markets+ paradigm. The draft proposal also recognizes the need for transmission owners to continue to recover their transmission revenue requirement while minimizing cost shifts to the native load customers of those transmission owners. NIPPC suggests that SPP's draft proposal does not yet strike the right balance between the beneficiaries of an optimized day-ahead market and the holders of the transmission rights which enable those benefits.

SPP suggests that the next phase of the detailed market design will focus on development of a multistage process where a reliability-based, physical resource commitment occurs followed by a purely financial and voluntary day-ahead market. But the exploration that SPP proposes for the next phase of market development is only to focus on the specific market timeline between the close of the day-ahead market and the posting of the day-ahead market results. It seems to have already decided the larger policy question of how much transmission capacity already under contract to transmission customers the market will use for its optimization.

For purposes of these comments, NIPPC assumes that the Western Power Pool's Western Resource Adequacy Program (the "WRAP") will serve as the framework for the "reliability-based, physical resource commitment" that the market proposal requires. The WRAP requires seasonal demonstrations that loads have capacity commitments supported by firm transmission rights. While there are limited exceptions allowed with respect to the transmission showings, generators who wish to offer capacity products to meet the WRAP requirements will still be required to hold firm OATT transmission rights sufficient to reach their intended customers (assuming the load responsible entities under WRAP require their counterparty generators to show up with those transmission rights, an already common practice in resource solicitations in the Northwest). Even though the WRAP requirement is seasonal, competitive pressures and concerns about market access will likely push capacity resources to procure transmission rights for a term longer than the duration of their seasonal capacity contract.

SPP proposes to cast a wide net to sweep up as much transmission capacity for the day-ahead market to optimize as possible. The goal to maximize transmission use is understandable, because the more transmission that is available to the market, the more generation resources can be dispatched in economic merit order to meet the energy demands of loads across the footprint. But these increased benefits for loads – lower energy prices – come at a cost. The cost is not borne by transmission providers.

To the contrary, the market design includes a new transmission product, Market Transmission Service ("MTS"), intentionally designed to insulate transmission providers from lost revenues resulting from decreased demand for short-term transmission rights. That cost is also not borne by loads who benefit from the centralized dispatch of the least-cost energy resources. Rather, the cost is borne by the generators who hold contracts for transmission service who find the value of those transmission rights substantially limited by the market design.

Consider a generator taking balancing area services from a Markets+ participant. The generator actively seeks capacity contracts to meet the resource adequacy needs of a load in the WRAP footprint. To secure those resource adequacy opportunities, the generator purchases firm transmission service to its customer (or a market hub such as Mid-C). If the generator releases its transmission rights to Markets+, the market may (or may not) dispatch that generator, but it is possible (and depending on the transmission contract path, it may be likely) that the market is using those transmission rights in its optimal centralized dispatch but without compensating the transmission customer (short of a potential congestion revenue payment which may not cover the full cost of the service). On the other hand, if the generator decides not make its transmission rights available to the market and elects to schedule its transmission rights to meet demand in the bilateral energy market, it will still be exposed to Markets+ settlements and/or uplift charges – essentially incremental charges -- for using transmission rights for which it has already fully paid.

NIPPC acknowledges the goal to use as much of the transmission system as possible to maximize the benefits of the market's economic dispatch of energy. This goal will likely provide significant cost savings to loads and create greater opportunity to maximize the deployment of non-carbon emitting variable energy resources. But those benefits come only at the expense of the holders of transmission rights who will see the value and quality of their transmission rights substantially eroded. NIPPC is sometimes at pains to remind policymakers and other parties that a market is not a one-sided phenomenon. Buyers alone do not a market make. If Markets+ is designed such that competitive sellers of capacity and energy see their commercial positions and investments unavoidably eroded, then participation in the service offering will suffer and consumers will therefore not benefit as much.

As NIPPC noted above, RTOs have many characteristics that the proposed Markets+ design does not[4]. NIPPC suggests that setting up a market design that maximizes centralized economic dispatch, but without these other attributes of RTOs, and that relies on uncompensated use of transmission customers' transmission rights will result in rates that are not just and reasonable. For example, knowing that transmission rights will have limited and uncertain value in the day-ahead market, generators bidding into resource adequacy procurement will seek to recover the full cost of the resource adequacy transmission requirement as part of the pricing calculation for their capacity. Because the WRAP requires a seasonal showing of resources and associated transmission, generators may be incentivized to include the full annual cost of transmission in the prices they quote for seasonal capacity needs. Accordingly, it is likely that pursuit of maximizing the economic dispatch of energy through the Markets+

[4] Including balancing area consolidation, elimination of separate and distinct transmission tariffs, a regional planning and cost allocation mechanism for transmission, and mechanism sto allow transmission owners to recover their full transmission revenue requirement under a flow-based system.

framework will result in significant increases in the cost for loads to procure capacity. While these higher capacity costs might be offset by the economic dispatch benefits of Markets+, it may result in cost shifts among loads and generators. Specifically, a vertically-integrated market participant with load, generation, and a portfolio of transmission contracts for which it receives cost recovery in its retail rates (such as an investor-owned utility) may find that it benefits more from the market's optimization of its transmission portfolio for resource adequacy and the Markets+ economic dispatch than a transmission-dependent load-serving entity or generator who cannot rely on recovering the costs of its transmission portfolio in its retail rates.

NIPPC also notes the significant feature of Markets+ that the program is only voluntary for transmission providers. A generator or load in a balancing area that joins Markets+ no longer has any option to participate in the market, but is forced into it. The generator or load not affiliated with the transmission provider will be swept into the Markets+ paradigm if it its balancing area service provider joins Markets+, even if the generator or load does not execute a participation agreement. Not only will the output and demand of those unaffiliated and potentially unwilling market participants be settled at the Markets+ day-ahead prices, but their transmission rights will be used to enable the market – whether or not they consent to that use.

In its last round of comments NIPPC expressed concerns regarding the proposed new transmission product – Market Transmission Service (MTS). Those comments do not appear to have been addressed in the continued development of MTS. The current draft outlines the concerns of transmission owners, and now clearly describes the intention to charge all energy (i.e., generation) and load a market uplift charge to compensate transmission providers for decreased revenues for sales of short-term firm and non-firm transmission service. As before, NIPPC is primarily concerned that the market will not allocate MTS costs to transmission customers who purchase and schedule on firm transmission rights acquired from one of the participating transmission owners. If implemented as proposed, both a generator that makes its transmission rights available to the market and is dispatched by the market and a generator scheduling service on its long-term firm transmission rights (and paying the full tariff rate for those rights) will also be required to pay the uplift charges to compensate the transmission provider for the revenue it lost as a result of its decision to join Markets+. These transmission customers derive no incremental benefit from the Markets+ MTS (in fact, they derive no benefit from Markets+) and therefore should not be required to incur incremental charges to serve their customers. NIPPC hopes further iterations of the market design by SPP will restrict recovery of costs for MTS to those customers who actually benefit from the service.

COMMENTS OF NV ENERGY ON SPP'S DRAFT SERVICE OFFERING FOR MARKETS +

October 26, 2022

NV Energy appreciates the opportunity to comment on the Southwest Power Pool's Draft Service Offering for Markets+, a Western day-ahead and real-time market and related services. NV Energy commends the SPP personnel, market participants, and the WIEB staff and state regulators who have participated in the intensive and collaborative stakeholder process that formed the basis for the Draft Service Offering. With Markets+, Western Balancing Authority Areas, their customers, regulators, and other stakeholders would have the ability to participate in day-ahead and real-time organized markets under a governance structure independent of any market participant or single state authority.

NV Energy recognizes the significant scope of work that remains to bring Markets+ from the conceptual to the operational phase. While NV Energy might prefer a more direct path to the RTO participation required by Nevada State law, we understand that the reliability, economic, and environmental benefits associated with expanded organized markets in the West can only be realized in cooperation with our Desert Southwest, Intermountain West, and Northwest partners who bring the transmission connections and diverse supply vital to the realization of potential market benefits.

These comments are not meant to be a comprehensive statement of NV Energy's position on the Markets+ design. We hope they are of assistance as the SPP team finalizes the Service Offering and identifies the issues that will need to be addressed in the Phase 1 tariff development.

I. GOVERNANCE

NV Energy supports the overall proposed structure of the Markets+ governance. The governance design draws on elements from the EIM Governing Body and the Western Power Pool's Western Resource Adequacy Program that that been supported by stakeholders in the West. Most importantly, stakeholders and regulators will have opportunity to provide substantial input into prioritizing and shaping initiatives under the oversight of the Markets+ Independent Panel. While the governance framework represents compromises on specific elements, it is all done with independence as the bedrock principle.

A. The Markets Plus Independent Panel

The Markets+ Independent Panel (MIP) will have expansive, primary oversight of Markets+ with a defined and limited scope for appeals to the independent SPP Board of Directors. The matters subject to joint authority with the SPP Board are appropriate. The size, composition, qualifications, and term of the MIP members are reasonable. NV Energy appreciates the change made in the Draft Service Offering so that the MIP chair will be determined by the MIP members rather than an SPP Board member making the design more independent in nature.

NV Energy generally supports the MIP sector-based selection process. While NV Energy strongly supports SPP's open meeting policy with respect to market design initiatives, we continue to question the approach of having the MIP Nominating Committee discussions in an open session. To ensure full and frank discussion among the Nominating Committee members, these deliberations should be closed to the public.

NV Energy also continues to object to the definition of "affiliate" and the limitation on a single vote for affiliated entities in the MIP member voting process. As NV Energy explained in our July 14, 2022, comments on the Draft Governance Straw Proposal, as defined, NV Energy would have an affiliate relationship with PacifiCorp since both are subsidiaries of Berkshire Hathaway Energy. If both utilities enroll in Markets+ they would have only one vote to determine MIP membership. Each utility serves load and is subject to the jurisdiction of separate states with independent policy goals and objectives. Therefore, both companies should have separate votes.

Currently, the proposal does not contain any limitations on the number of terms a MIP member may serve. NV Energy notes that the WRAP Board members are subject to a limit of two three-year terms and that the EIM Governing Body has a restriction of three three-year terms. We believe there should be a balance that recognizes both the benefits of institutional expertise and the opportunity for new perspectives and request that SPP further consider the potential benefits of term limits.

B. Formation and Operation of the Markets+ Participants Executive Committee

One issue not addressed in the Draft Service Offering that should be clarified before entities commit to the next phase of Market + development, is the Governance structure that would be in place for the Phase 1 effort. For example, will the detailed design and tariff drafting be done by work groups under the Markets+ Participants Executive Committee (MPEC) or will SPP continue the stakeholder process used for the Draft Service Offering. NV Energy notes that WRAP stood-up its participants committee to help oversee preparation of the FERC filing and implementation activities.

With respect to voting for at the MPEC, SPP envisions the formation of three sectors: (1) investor-owned utilities, (2) public power, and (3) independents. Each sector represents 33 1/3% of the vote. An action would be deemed approved by the MPEC if the average of these percentages is at least 67%. In our July 14, 2022, comments, NV Energy expressed the concern that this approach was not geographically balanced. Given the prevalence of public power entities in the Northwest and depending on the composition of IOUs participating in Markets+, the Desert Southwest could be a minority of all voting sectors. To address this concern, NV Energy would propose that to be approved by the MPEC a matter must gain support from both:

- 67% of the three sectors as proposed by SPP and

- 50% of the entities in both: (1) the Desert Southwest and Intermountain West, and (2) the Northwest.

This voting structure would ensure a balance with respect to both the types of participants and the geographic dispersion of those participants. While voting is advisory to the MIP's consideration and not dispositive of whether an initiative moves forward to a FERC filing, it is an important indicator of participants' preferences. It should be valuable for the MIP to be informed about the regional effect of potential market improvements.

NV Energy would expect the Phase 1 process to develop additional details on the timing and manner in which a stakeholder could appeal any action or inaction to the Markets+ Participants Executive Committee and to the MIP.

II. RESOURCE ADEQUACY DESIGN

SPP states that a common resource adequacy requirement for Markets+ is an appropriate and necessary prerequisite to market participation as this will enhance reliability by verifying that each load-responsible entity contributes its individual share of the overall capacity needs of the market footprint. SPP notes that significant momentum and progress are being made in the Western Resource Adequacy Program (WRAP) and anticipates stakeholders will select this program as the common, FERC-approved resource adequacy program for Markets+. As recognized, by SPP this forward resource adequacy requirement would be translated into a must-offer requirement to ensure resource sufficiency in day-ahead and real-time.

The WRAP team has borrowed the computer term "interoperability" to refer to the need for their program to work in an integrated fashion with the expanded western organized market options. In particular, there will be a need to coordinate the WRAP holdback requirement with the Market+ design. For SPP, the combination of a forward Markets+ resource adequacy requirement (based on the WRAP forward showing) and a day-ahead must-offer quantity (based in part on the WRAP operational program) may negate the need for additional daily or hourly resource sufficiency tests. NV Energy strongly supports this approach as a vast improvement over the well-documented problems associated with the highly complex EIM resource sufficiency evaluation.

As part of the next phase of detailed market design, SPP proposes a joint taskforce be created to facilitate the necessary coordination needed between Markets+ and WRAP. NV Energy supports this important action. One issue to be further examined in Phase 1 is the need for common participation in the WRAP program rather than leaving the option for a WRAP "equivalent", at least as it relates to load serving entities in a single Balancing Authority Area. Without all load serving entities in a single Balancing Authority Area participating in the same program, the Balancing Authority Area could be left responsible for any resource inadequacy in a footprint. Participating in a common resource adequacy program can maximize the diversity benefits and address issues with respect to program administration, forecasting, resource qualification, and determination of planning reserves while ensuring the entire Balancing Authority Area footprint has sufficient resources to serve load.

III. MARKET OPERATIONS

A. Electric/Gas Coordination

SPP utilizes a non-binding multiday informational study that provides a commitment and pricing forecast based on the latest available data. It runs daily after the day-ahead market posting and has a study period covering the next three to seven operating days at an hourly granularity. There needs to be further exploration in Phase 1 as to the reliability of these outputs with respect to coordination of gas procurement. Additionally, Phase 1 should further develop the details of the must-offer requirements for the Day Ahead and Real Time timeframes while considering issues that may arise with gas procurement.

IV. TRANSMISSION

Transmission service providers within the Markets+ footprint will maintain their open access transmission tariff (OATT), administer their open access same time information system, and continue to sell firm and non-firm transmission service as they do today prior to and after the day ahead market window. Markets+ will economically dispatch energy across the market footprint using transmission capacity less any capacity not available for market use (for example capacity owned by a non-market participant or reliability set asides). Importantly, transactions that either import into or wheel out of or across the Markets+ footprint will continue to pay pancaked transmission rates based on the approved rates of the transmission service providers whose systems make up the wheel.

Markets+ will utilize regional market dispatch to serve all participating load, causing revenues from short-term firm and non-firm transmission capacity sales to decrease. A new product, market transmission service (MTS), will facilitate the receipt of energy from any resource in the market region to meet load obligations of Markets+ participants. The MTS portion of the transmission providers' annual transmission revenue requirement (ATRR) will be recovered through a market charge and will be applied to all energy and load cleared in the real-time market to recognize the market use of transmission and to offset the expected reduction of short-term firm and non-firm transmission capacity sales.

A. Recovery of Potential Lost Transmission Revenue Credits

Market use compensation will be provided from the market via an MTS billing determinant using a combined revenue requirement from the OATTs. The MTS revenue recovery amount will be defined by a transmission provider's qualified recovery amount (QRA), which is based on the revenue a transmission service provider historically received from sales of short-term firm and non-firm transmission service. SPP states that any under or over collection of MTS revenue collected by the market would be applied as an adjustment by the respective transmission service provider when calculating future ATRRs. NV Energy questions whether the adjustment should be to the future MTS revenue recovery amount specifically and not the transmission provider's general ATRR. An average of a transmission provider's previous three-year short term firm and non-firm will be used to establish the initial QRA.

A qualified revenue ratio (QRR) based on a comparison of short-term firm and non-firm revenues versus the total ATRR will be determined for each transmission service provider. This ratio will be applied to current and future year ATRR to account for changes in ATRR over time. It will also be used to calculate the appropriate ratio of potential transmission revenue credits associated with transmission expansions such as NV Energy's own Greenlink project.

The stakeholders have also recognized that since transmission service providers will continue to be able to sell short term transmission capacity before and after the market closes, that there will be a level short term firm and non-firm revenues that will not need to be recovered through the market. SPP is proposing a recovery scaling factor to prevent over-recovery.

NV Energy supports the overall approach to maintaining historic levels of revenue credits, accounting for transmission system expansion and applying and adjusting the scaling factor to prevent over-recovery; however, we believe the calculation as described in the draft service offering does may not be accurate. SPP proposes the MTS Revenue Recovery Amount (RRA) equal to the QRA multiplied by the Qualified Revenue Ratio (QRR) multiplied by the RSF. Using this equation, it seems that a utility would under recover lost short-term revenues. Instead, NV Energy questions if the QRA should instead be used as a cap such that an entity cannot recover above this amount, and the RRA calculation should equal (the average 3 years prior TSP ATRR * QRR) * Recovery Scaling Factor (RSF). By using the TSP ATRR, a TSP can update their respective ATRR and have the QRR ratio be consistent and adjusted by the market scaling factor for anticipated market recovery of the lost short-term revenues. This seems to be more representative of calculating lost revenues. NV Energy understands that significant additional details need to be worked through in Phase 1 regarding the methodology to preserve an appropriate level of transmission revenue credits.

B. Congestion Allocation

In the Draft Service Offering, SPP is proposing that congestion rent allocation be allocated to firm transmission rights holders, NERC scheduling priority 7, with the allocations based on transmission rights, not schedules. NV Energy believes that it may be appropriate for long term point-to-point transmission customers to be allocated congestion rents based on their rights instead of their schedule because a long-term firm point-to-point customer must pay for the capacity of the reservation regardless of if they use the capacity.

NV Energy continues to question the lack of protection to short-term firm customers who pay the same OATT transmission rate today and enjoy the same ability to move power from points of receipt to points of delivery without congestion exposure. This is an issue that should continue to be examined in Phase 1.

NV Energy does not support SPP's proposed allocation of congestion rents to network integration transmission service customers (NITS) based on using the maximum quantity of network transmission rights set equal to a three-year average of the customer's network load multiplied by 103%. A NITS customer provides an annual 10-year load forecast and updates their capacity reservation to meet forecasted peak demand. As explained during the stakeholder process, NV Energy's NITS customers may have seasonal or monthly loads and employing an annual peak number significantly overstates their transmission utilization. This reserved capacity is not owned or paid for by the NITS customer. Rather, the NITS customer only pays a load ratio share based on their actual load at NV Energy's system peak (coincident peak) each month. An individual NITS customer is only permitted to use the transmission to meet their load at that moment on either the primary (7FN) or secondary (6NN) basis. In this manner, all NITS customers ***collectively*** support the transmission system and are due compensation if any third party non-firm user or market dispatch produces congestion revenues over any unscheduled transmission capacity. SPP's proposal on assigning congestion revenues to a specific NITS customer is inconsistent with the nature of the service and the manner in which it is charged. Stated another way, SPP's proposal would provide a windfall to certain NITS customers who are not utilizing and paying for transmission and expose other NITS customers to unwarranted congestion costs when they are exercising their 6NN rights. Markets+ is an amalgamation of the historic OATT rights and practices with the RTO flow-based dispatch. The proposed congestion rent approach for network customers may fail to meet that objective in a just and reasonable manner. As SPP explores this issue further in Phase 1, NV Energy would encourage SPP to examine the possibility of working with the transmission service provider to develop a methodology that hold the NITS customers who schedule on a 7FN or 6NN basis harmless from congestion costs with any additional revenue or shortfall being allocated to the NITS customers on a load ratio share basis.

V. GHG

SPP's ***current*** deign proposal, utilizes a zonal approach that supports the classification of three distinct categories of resources serving the load in a GHG zone: GHG zone internal generation, specified-source imports and unspecified-source imports. NV Energy is not supportive of a proposal that incorporates a hurdle rate or adder into the market optimization that discriminates against resources located outside the GHG zone or zones. In particular, NV Energy can face situations where it is seeking to manage overgeneration of renewable resources on its system. These non-emitting resources cannot be disadvantaged in a single market optimization. In designing the GHG program, SPP must address potential discrimination against non-emitting resources located outside the GHG zone that are not under contract to service load in the GHG zone. In addition, NV Energy questions whether it is appropriate for all resources that qualify for the specified approach to retain their GHG revenue while the unspecified revenue would be collected and returned to the GHG zonal load.

VI. IMPLEMENTATION

SPP anticipates it will take 21 months and approximately $9.7 million to prepare the tariff and filing package for submission to FERC. The cost and timeline seem reasonable. NV Energy will need additional specificity on how the costs are to be allocated and the structure of the work groups, stakeholder process and decisional framework applicable to Phase 1.

At the end of the 21-month period, potential participants will pay a monthly rate of $500,000 per month to support the responses, technical analysis and research necessary to gain final approval by FERC. SPP must provide far more detail on these costs which seems highly dependent on the number of participants. Stated another way, the litigation costs should be reflective on the number of protests not the number of potential Markets+ participants.

PUBLIC GENERATING POOL

Opening Remarks:

Public Generating Pool (PGP) is a trade association representing 11 consumer owned utilities in Oregon and Washington, who own and operate their own resources in the Pacific Northwest and purchase large portions of the BPA system output.

PGP appreciates the opportunity to provide comments on the SPP Markets+ Draft Service Offering and looks forward to participating in further discussion on the topic. Overall, PGP finds that the Draft Service Offering includes an appropriate level of detail and information to enable potential participants in Markets+ to decide whether to participate in Phase 1. These comments are therefore primarily focused on areas that should be part of further detailed conversation in Phase 1. Where there are specific recommendations to change language or substance in the Draft Service Offering, that is so noted.

Given the stakeholder-driven approach of SPP and the current phase of market development, PGP is focusing on areas that warrant further stakeholder engagement, either through smaller working groups or more meetings with the current design teams to enable further refinement of the draft towards a Final Service Offering. These comments assume that much of the substance of PGP's prior comments will be addressed by working groups in Phase 1 and therefore are not repeated here. PGP's prior comments are attached as an appendix for reference.

Considering the significant progress made in development of a shared understanding among stakeholders, and that the next phase of design may have a smaller participant pool, the beginning of Phase 1 would be a good time to revisit some of the design principles that were established early in the SPP outreach effort. This refresh could add some additional clarity and nuance so that these principles will be robust enough to use as a framework to evaluate design components, ensure examples are addressing stakeholder concerns and objectives, and to find areas that stakeholders have divergent views to facilitate meaningful dialogue. Many of these principles previously established by Markets+ stakeholders are reflected in the Draft Service Offering but are not sufficiently detailed to truly guide the design through the next phase.

Stakeholder Process/Governance

PGP support the governance proposal included in the Draft Service Offering and appreciates recent modifications to enable the Markets+ Independent Panel (MIP) to select its own chair and to allow a waiver process for the annual Markets+ Market Stakeholder fee. We also support the proposed committee and voting structure for the Markets+ Participants Executive Committee (MPEC), but would appreciate additional information regarding the extent to which the MPEC will be formed during Phase 1 and if a different voting structure may be needed for that effort. PGP continues to have some concern that there may be conflicts or issues that arise, particularly if there are appeals, by virtue of having an SPP Board member as a full voting member of the MIP. In addition, while supportive of the basic structure, PGP believes that some further conversation may be warranted with respect to how working group and task force participation is established. While a sector-based approach may be time-consuming and potentially cumbersome, it could have benefits with respect to ensuring equitable representation across stakeholders. On the other hand, there may be potential value in the more flexible approach included in the Draft Service Offering. PGP supports the proposal as drafted but would appreciate further discussion on this topic as Phase 1 and Phase 2 evolve. Given the proposal to conduct a governance review at the request of the MPEC and no later than three years after market launch, we are comfortable with the proposed approach notwithstanding the relatively minor issues articulated above.

While PGP supports the establishment of committees and stakeholder working groups as outlined in the proposal, the Draft Service Offering should include additional detail with respect to how stakeholders will participate during Phase 1, including whether and how working groups will be formed and what participation requirements may apply. As a trade association representing entities who may be participating in Phase 1 and who may ultimately participate by virtue of having generation and/load inside a participating Balancing Authority Area, PGP has an interest in participating in Phase 1 but is unlikely to be in a position to fund even a small portion of the costs specified. At a minimum, SPP should consider adopting a framework that allows potential future Markets+ Market Stakeholders to participate in Phase 1. If a fee structure is adopted, it should similarly include a waiver for nonprofit entities.

In addition, PGP members may desire to work together to provide adequate staffing and engagement to support SPP through the process and would appreciate additional information that would help inform how the effort will need to be resourced. For this reason, the Draft Service Offering would benefit from an explanation of the portion of the governance framework that will be in place for Phase 1 of the initiative, and if there needs to be some process added to facilitate the use of these structures as applicable. Once there is funding, we anticipate an enhanced level of staffing will be required and so to the extent that time commitment estimates can be developed for various engagement processes, it would help participants to align staffing accordingly.

For Phase 1, further information is needed on the proposed allocation of funding and what it implicates for participation framework, voting, and the ability to be chair or on a work group or task force. Given the known list of initial participants, please define the framework further and in a way that would enable additional participants to join later in the process and still contribute funding if applicable.

Participation model

PGP appreciates the clarifying language on the participation framework included in the Draft Service Offering in some areas, and the areas for further engagement that are also highlighted. Generally, the Draft Service Offering is sufficiently detailed, but in the area regarding the LSE's "secondary" relationship with the MO seems in conflict with the initial definitions of "Market Participant" that were discussed in the draft design and the Portland meeting. Further clarification is recommended for the final offering.

PGP provides some additional thoughts for consideration in Phase 1:

- Given the unique nature of this construct and the preservation of separate BAAs, TSPs, and TOPs, more detail and consistent explanation of BAA and TSP roles and responsibilities *vis a vis* the Markets+ Market Operator will be required throughout the revised design document and tariff language.

- Further clarification of roles and responsibilities between LSEs and BAAs is still required.
- The external resource participation and import/export framework needs further detail. Given the footprint of the potential market is still to be determined, there will likely be some participants with long-term transmission to external resources that have been relied on for load service. Entities will need examples for how settling these resources at the interface will preserve existing contract paths to delivery as applicable vs the use of pseudo ties or service flow constraints, and how these paths to external resource delivery may differ from a prioritization, dispatch, and settlement perspective.
- PGP would appreciate more detail on the multi-day advisory run including frequency, and visibility of results, to better understand how it may align with the WRAP operations program and other pre-market activities
- We support further discussion on the grouped hydro model and joint operating unit concepts introduced in this draft.

Transmission Commitment, MTS, and Congestion Rent

PGP's perspective on a transmission framework is rooted in the principle that open access should be honored and cost shifts minimized. PGP appreciates the general principles that are outlined on page 25 of the Draft Service Offering, and the acknowledgement that more detail is required.

PGP recommends revisiting the guiding principles and indications at the start of Phase 1 on Transmission Commitment, MTS, and Congestion rent design to highlight areas needing analysis and the demonstrative examples that will be required to effectively engage stakeholders. Clarifying what we are trying to achieve will help to focus the effort up front. Some more detailed principles for consideration in Phase 1 that align with PGPs and SPPs broader stated frameworks include:

- Design should reflect existing prioritization of grid access with firm transmission rights having the highest priority.
- Philosophically, NT transmission rights should be an effective hedge for delivery of NT resources to load and examples demonstrating this using different resource types and transmission paths will be critical to bring participants along. Linkage to resource flows may be required to make the hedge effective.
- When NT resources are not cleared, the LSE should receive the benefit of lower market prices vs variable operating costs of the displaced resource. When they do clear, congestion costs on the NT resources should be recuperated with congestion revenues on the appropriate path to delivery.
- The corresponding philosophy for Point-to-Point rights as a hedge and applicability needs to be established.
- Congestion signals should be sent in a way that the entity that mitigates them receives the value (or benefit of avoided cost). PGP notes given the multiple TSP and varying resource types that this may require more granular calculations.
- Design should clearly define and limit free-ridership.
- The market design should not disincentivize investment in Long-Term transmission rights, and this criteria should be considered with every aspect of the transmission commitment, revenue collection, and allocation in the design.

- Real-time congestion management should follow similar principles and methodology to Day-Ahead to minimize exposure or disconnects.

In Phase 1, participants will need to see detailed examples including the resource to load delivery and corresponding congestion settlement in alignment with transmission access and priority. The ultimate design and examples need to demonstrate an understanding and preservation of Open Access Transmission Tariff rights to potential Markets+ participants.

Resource sufficiency

PGP supports the use of the WRAP as the default program and that this may reduce the need for a more detailed resource sufficiency calculation. In Phase 1, similar to the transmission commitment and congestion allocation, resource sufficiency is an area that likely warrants revisiting some more detailed principles that the design team is working towards. Some examples include:

- The design should maintain any diversity benefits gained through the implementation of the WRAP program.
- The must offer should be as aligned with the forward showing and operational program as possible.
- A mechanism needs to be introduced to translate between any differences in the way WRAP and Markets + participants are defined.
- Short-term resource capacity accreditation should be transparently provided through market processes, potentially through a regional approach to VERS forecasts in the multi-day and DA timeframes that aligns better with WRAP analysis.
- Participation in Markets+ should not jeopardize a BA's ability to meet its NERC reliability obligations.

Greenhouse Gas Pricing and Dispatch

PGP supports SPP's proposal to utilize a zonal approach to include the cost to serve load in states with greenhouse gas (GHG) programs. The Draft Service Offering appropriately articulates what the GHG design needs to accomplish and accurately characterizes supply redesignation concerns. PGP looks forward to working with SPP and other stakeholders in Phase 1 to continue to define the details of the proposal including collaboration with the Washington Department of Ecology to articulate state regulatory requirements.

Other Market Processes and Products

From a scoping perspective, there are items that may need to be set aside for the initial implementation, or more background may need to be provided to guide a decision. A couple areas of note here are:

- If operating reserves are handled by BAs, and scarcity pricing is established for when operating reserves are low, Phase 1 stakeholder processes should evaluate the need (at all) for scarcity pricing and if/how this differs from putting a penalty on the power balance constraint.

- The studies previously shared by SPP discussing virtual participation did not demonstrate clear or consistent benefits. PGP would like further information before supporting a day-one participation framework for virtual market participation.
- Any market design needs to consider what is required to address seams issues with the Western bilateral market and other organized markets in the West
- Considering the unique design of the Markets+ and any newly established design principles, objectives of any market-specific price cap and/or floor should be re-established by the design groups.
- Given the ongoing role of the separate BAs, the role of reserve deployment in price formation will need to be better articulated.

PGP looks forward to further discussion around other approaches to arrive at the stated objectives for the Option 2 in unit commitment and RUC, as well as additional detail on the way RUC and the true-up of financial and physical markets would work.

Conclusions

PGP supports the progress made to date and looks forward to continuing to engage in the market design process.

APPENDIX A: PGP Prior Comments on SPP Markets + V2 Design Document

Opening Remarks:

Public Generating Pool (PGP) is a trade association representing 11 consumer owned utilities in Oregon and Washington, who own and operate their own resources in the Pacific Northwest and purchase large portions of the BPA system. PGP appreciates the opportunity to provide comments on the revised SPP Markets + Design Document. The Markets + initiative is a significant development that if implemented, will have a major impact on how nearly all generation is transacted across the West and will impact those entities that choose to join Markets +, and those that may not. Given the importance of this market evolution, PGP has partnered with other public power utilities in the Northwest "NW Public Power" to develop common interests on principles and elements that we believe should be applied to any centralized day-ahead market that develops in the Northwest, including Markets +. These principles can be found here.

PGP is supportive of the Markets + efforts to date, in particular the progress on governance. PGP views Markets + as a significant opportunity for our members that may also carry potential risk, depending on how the market is designed and the governance structure that accompanies it. For Markets + to be successful, SPP will need to strike a careful balance between providing market features and elements that stakeholders desire, preserving existing rights and minimizing complexity. In addition, Markets + must be able to successfully interface with the newly developed Western Power Pool resource adequacy program (WRAP) and be implemented on a timeline that balances the desire to move quickly with taking the time to develop an equitable and durable market.

PGP also notes the competing CAISO EDAM initiative, day-ahead market enhancements (DAME) initiative, the price formation enhancements initiative, and EDAM governance process that CAISO is undertaking. PGP will be considering CAISO's proposal to highlight key differences with Markets+, potential seams issues, and other areas of consideration for a potential multiple-market future in the West.

Given the stakeholder-driven approach of SPP and the current phase of the document, PGP is focusing on areas we believe warrant further stakeholder engagement, either through smaller working groups or more meetings with the current design teams to enable further refinement of the design draft towards a final service offering.

Stakeholder Process

PGP appreciates SPP staff's dedicated efforts in workgroups, availability in informal meetings, and responsiveness to stakeholders leading to this draft design document.

- Going forward, PGP recommends some improved communication practices to ensure all interested stakeholders can participate meaningfully. If implemented, these changes will help ensure that relevant staff within organizations can either attend meetings or be consulted and that representatives attending meetings are able to accurately represent their organizations' positions. Some suggestions include:

  - Notifications for all meetings and comment deadlines, including time/date changes, sent out as soon as practicable via Markets+ Exploder.
  - Agendas posted minimum of 3 days, preferably 1 week, prior to meeting; materials posted minimum of 24 hours, preferably longer, prior to meeting.
  - Data behind any market analysis and associated calculations should be shared with participants to improve transparency.
  - These recommendations are especially important during phases of market design development that rely primarily on meetings rather than on written proposals.
- PGP looks forward to seeing comments from other participants and communication regarding how these comments will drive the process and substance of the Markets + effort going forward.

Participation model

The Markets+ participation framework should consider the following:

- At the appropriate time, PGP requests additional information and/or discussion about the relationship between the Market Operator and LSEs that are not BAAs/TSPs, as well as whether and how we may expect LSE's relationship with their host BAAs/TSPs may change under the Markets+ framework.[1] For example:
  - Would LSE's bid/forecast their own load or would this activity be conducted at the BAA level?
  - Would Markets+ settle directly with LSEs or would settlements generally go through BAAs/TSPs?
- PGP would like to better understand the extent to which an LSE embedded within a participating BAA would be able to fully hedge and be held harmless. Several PGP members are LSEs within the BPA BAA whose participation in *any* day ahead market is fully dependent on BPA deciding to join. We expect any such decision from BPA to require the support of a wide swath of BPA customers, some of whom may need to be convinced of a low risk profile. PGP recommends SPP host additional discussions on the Service Flow Constraints concept, and develop some specific examples in the congestion rent allocation discussion that cover resource to load delivery, including any congestion exposure on the resources. Such discussions should include consideration of how these concepts would relate to the expected future resource mix and other system changes over time to help LSEs understand potential risk and risk management approaches within Markets+.
- The framework should further clarify threshold connectivity and footprint requirements for Markets+ to be a viable option; for instance, can an entity who is connected to the rest of the footprint through non-participant transmission still participate in Markets+. Similarly, updates on the RTO west and new seams that it may introduce would help participants new to SPP markets maintain a core understanding aligned with the WEIS members who may be more familiar with other SPP processes at this time.
- The external resource participation framework would benefit from further discussion and may warrant a specific working group to better define the framework, including explaining the potential

[1] Under the EIM, LSEs without participating (bidding) resources have no direct interaction with the market operator (i.e., all load forecasting, generation/transmission scheduling, and settlements are all handled at the BAA level), and we recognize that a different relationship between these three entities may be appropriate for Markets+.

benefits and addressing concerns of potential free ridership, impacts to reliability, and any seams issues introduced with multiple market frameworks interacting in the west.

Transmission commitment

PGP's market design principles state that a transmission framework should honor open access principles and minimize cost shifts. PGP urges SPP to consider the following in any draft offering:

- PGP appreciates that maximizing transmission available to the market should produce the most efficient overall commitment and dispatch solution. PGP is supportive of this goal and wishes to better understand the implications and any potential risks for individual entities of the "all-in" approach to transmission.
- It appears that the "all in" approach removes or reduces control of how to use and manage existing transmission rights. For example, it appears that by default, a transmission customer's long-term rights that are unscheduled at the start of the day-ahead market would be made available to the market for use without the customer taking any action. In the current bilateral framework, transmission customers regularly schedule on their firm transmission rights between pre-schedule and real-time to reflect changing operational conditions and market opportunities (e.g., load and VER forecast changes, hydro availability, etc.). PGP believes that additional discussion is needed for transmission customers to understand the impacts of SPP's proposed transmission commitment framework. Specifically, stakeholders would benefit by walking through some structured scenarios in which a customer responds to changing conditions after the preschedule/day-ahead timeframe. PGP and its members would be happy to work with SPP staff on developing the scenarios. The scenarios could cover the full operational timeframe from pre-schedule through to real-time using different resource types and compare the operational and financial impacts of:
    - (Base case) The customer scheduling on its long-term firm transmission rights in today's bilateral framework between the preschedule and real-time timeframes
    - (Hybrid option) The customer schedules on its long-term firm transmission rights after the Markets+ day-ahead market runs; this schedule conflicts with the market usage of the transmission.
    - (Full market option): The customer does not try to schedule on its long-term firm rights and relies solely on the real-time market to address the changing conditions.
- As the system evolves toward a higher percentage of renewable resources, there is a potential high-congestion scenario where some resource participants may be better off with a long-term and/or pancaked transmission rate at a fixed price to deliver resources to a load rather than paying and receiving congestion rents on the path, depending on the congestion rent allocation approach. PGP would appreciate some further examples of how the congestion rent allocation methodology provides a hedge for various resource types, including hydro, particularly in constrained conditions, and non-dispatchable resources.

Market Transmission Service

The introduction of the Market Transmission Service (MTS) rate and revenue allocation brings up some interesting questions that could likely be answered for all participants with some further analysis and data. If data sources to drive the historical secondary revenue calculations are public, PGP suggests that SPP make the dataset used for MTS analysis available so that potential Markets + stakeholders may propose alternate approaches to the cost recovery and better understand the differences between entities for this purpose.

- PGP understands that the purpose of the Recovery Scaling Factor (RTS) is to avoid overcollection. It is less clear how the 50% value was derived and whether it is the appropriate value for all TSPs. It may be possible to use a more data-driven approach to calculating this metric, or that the calculation could consider the residual short-term sales revenues directly to avoid overcompensation. The scaling has the potential to introduce cost shifts depending which participants are more impacted by the DA market formation. Legacy contract arrangements and resource-specific operational protocols may also play a role. PGP supports the proposed formation of a Transmission Working Group to monitor and potentially adjust the revenue recovery calculation, but suggests that additional analysis may improve the calculation and default methodology at the outset.
- Some potential Markets + participants have much of their systems fully subscribed, and as a result use significantly more redirects within the operational time frame. Data and analysis on the historical redirects may support the MTS product development for alternate use of the system when Markets+ needs to redispatch or redirect use. PGP recommends careful consideration of how this aligns with any congestion rents framework.
- From a process perspective, the current draft does not specify what elements of MTS collection and redistribution will be reflected in the SPP tariff, the service agreement, or participant OATTs. Given that OATT revision is required, PGP requests additional guidance on how this fit into the overall market development timeline and participation framework.

Congestion Rent allocation

Congestion paid by load and the corresponding re-allocation of the congestion costs to transmission rights holders is a critical component of the market design, and an opportunity to evolve the status quo to align better with evolving resource mixes and potential changes to the system. PGP supports the transmission usage goals stated in the transmission design meeting from September 7th, including proper distribution of congestion rents, maintaining Network and LT PtP sales and purchase incentives, and supporting clean and renewable programs. Given these objectives, it seems the calculation could use some additional nuance and documentation within the design, and may warrant other stakeholder discussions around the broader design goals.

- PGP acknowledges that congestion rent collection and allocation is not a simple task and may require significant computational effort. The alternative methods proposed may seem similar from a results perspective, but they may be quite different regarding how they may apply accurately to Network vs Point to Point customers, and their ability to fit with a generation source to provide a hedge for bringing generation to load.
  - PGP requests further examples using SPP market data comparing the approaches including an owned resource at the source, using a hydro resource, a wind resource, and an inflexible thermal resource to better highlight the differences between the approaches.
- SPP has presented options for monthly and daily TSR submittal. PGP supports further discussion on the tradeoffs associated with these two options. Based on our understanding, we believe that more frequent TSR submittal would more accurately reflect changing and the actual congestion that participants would be exposed to. Further, daily TSR submittal may encourage continued purchase of daily firm rights within the month. On the other hand, more frequent submittal would require a

greater administrative effort. We would be interested in hearing perspectives on a more granular approach from SPP staff and other stakeholders.

- It is also not clear whether the TSRs submitted could be more granular than the submittal timing. For example, if TSRs were submitted on a daily basis, is it possible for the TSRs to vary hourly throughout the day, assuming all had the appropriate priority? As above, this may better align with the actual congestion that participants are likely to be exposed to. What are the limitations from re-allocating based on DA scheduled TSRs to link more directly to congestion faced by generators and/or loads, and to better align with a future system with a higher penetration of renewable resources?
- PGP would support further analysis to find a solution that minimizes cost shift for participants and aligns better with the expected system evolution to fully capture the proposed benefits of an integrated DA market, especially given recent policy supporting ongoing and potentially significant negative bidding strategies for many new resources.
- The market-to-market congestion allocation section (p.51) notes it would require significant agreements and would likely be considered post Market + launch. What does this indicate for the default methodology prior to any market-to-market agreements? Given the potentially significant market to market connections, PGP notes that this area may not be able to wait until after a Markets+ launch.
- PGP would like to better understand how TSR resales and redirects, which are widely used in BPA's system today, would fit into the eligibility framework.
  - For resales, would the purchasing or selling entity retain the ability to submit the TSR for congestion rent?
  - For redirects, would the customer be eligible to submit TSRs on the original or redirected paths?
  - Do the answers differ for redirects/resales that are on a shorter timeframe than the TSR submittal frequency (e.g., how would redirects and resales of daily transmission rights fit into a monthly TSR submittal framework)?
- For the Allocation equation, to the extent that total congestion revenue collected by the market is less than the total revenue indicated by the sum of submitted TSR MW * (Source LMP – Sink LMP), PGP would prefer that any "shortfall" be limited to the transmission elements or transmission systems that are the "cause" of the shortfall, rather than socialize the shortfall across the market footprint.
  - For example, if 1000 MW of TSRs were submitted on a path that was derated down to 400 MW, the congestion rent collected on that path would be only 40% of the revenue needed to fully pay the rights holders the difference between the source and the sink LMPs. Ideally from a cost causation perspective, that shortfall should be limited only to the rights holders on the derated path, rather than contribute to any overall shortfall across the market footprint.
  - We acknowledge that in an interconnected transmission system, identifying the cause of a shortfall and the relevant TSRs to which a shortfall should be applied may be challenging, but we would welcome additional discussion on this topic, including as to whether the benefits of more precise calculations would outweigh any increased cost to implement them.
- Can SPP please confirm PGP's understanding that SPP would use a consistent congestion rent allocation methodology for both intra-BAA and inter-BAA paths within the Markets+ footprint, and that congestion rent would be allocated directly from SPP to the transmission rights-holders (and not through the TSPs/BAAs).
- Nearly all discussion to-date has been on day-ahead congestion rent allocation. We also request that SPP hold a discussion on real-time congestion rent allocation.

  - We would like to understand the tradeoffs between allocating real-time congestion back to rights-holders under a similar methodology as proposed for day-ahead congestion rent relative to other allocation approaches.
  - Allocating to rights holders may help keep rights holders whole if congestion patterns materialize differently in real-time than in the day-ahead market, and therefore may address concerns around a reduced ability to schedule on rights after the day-ahead market.
- PGP appreciates the hedging analysis provided in the 9/7 slide deck. We understand that the comparison was between congestion rent allocated and Load MW*MCC.
  - It would be helpful to see some "case studies" of entities with large differences between rent allocated and Load MW*MCC (both "over-hedged" and "under-hedged" examples) to better understand the drivers of these differences.
  - It would be also useful to compare congestion rent allocated to the TSR MW*(Sink LMP – Source LMP) during each sample hour.
  - If data driving this analysis could be made available for participants, it would improve everyone's understanding.

Resource sufficiency

PGP supports a resource adequacy and sufficiency program that promotes reliability, ensures equity, and can be applied consistently while limiting the ability for participants to lean on the market or use it to avoid long-term procurement of adequate supply. PGP members appreciate the initial concept of aligning resource adequacy requirements with the Western Resource Adequacy Program (WRAP), but more work is required to establish how this may translate to a meaningful Markets + Resource Sufficiency requirement if required. A stakeholder group or joint task force including WRAP participants and WPP staff would be best positioned to support Market + in the development of these design features. PGP recommends Markets + begin this group as soon as possible, as RA/RS is likely a core area of concern for any potential participant.

- The region's current Resource Adequacy program is still structured around the ability to manage short term reliability challenges through a bilateral framework and includes market aid and transaction language structured as such. Any DA market will need to preserve or co-exist effectively with the WRAP operational framework and any contractual arrangements that may result. The service offering would benefit from more clarity regarding the interface between Markets+ and WRAP, particularly if their respective footprints are not aligned.
- How will the Load Responsible Entities who participate in WRAP be differentiated within Markets + if Markets + is applying any Resource Adequacy or Resources sufficiency test only at the BAA level?
- How will Markets + honor the operations program and delivery requirements developed by WRAP? Any operations program or sufficiency arrangements will need to be appropriately enabled through the transmission use model and market timelines and should be a constant consideration in development of those components of the market offering.
- Additional work is needed to clarify how Markets + achieve the design objective of cost causation and allocation using market mechanisms, and what these mechanisms may be, particularly in strained system conditions.
- In regional analysis of market development in the west, one significant benefit category was reduced capacity need through diversification of the capacity supply. PGP supports further analysis of how to incorporate a diversity benefit in any resource sufficiency protocol to begin to capture these benefits for the region.

- Any seams issues that develop due to the market footprint and corresponding alignment with the WRAP will need to be clearly addressed in the design. Seams may consider WRAP participant to non-participant, and Markets + participant to non-Markets+ participant.
- How will priority of transfers be determined during challenging system conditions?

Unit commitment and RUC process

PGP appreciates SPP's efforts to think innovatively in this space with the Option 2 proposal, but there are many aspects of this approach that are not clear.

- While the desired outcomes are loosely stated, clearly illustrating the problem that this new approach is meant to solve would support engagement in the solution development. This approach seems aligned with managing issues driven by long-lead thermal resources, that may be phasing out of the system. Noting the potential system management challenges may be changing over time with the system mix, is this approach still the best long-term solution?
  - PGP recommends that different system mixes be considered with any potential unit commitment and RUC analysis.
- We support efforts to get the commitment right at the outset, which appears to be goal of RUC Option 2.   However, PGP members are concerned about unintended consequences of completely detaching RUC from financial DAMKT especially if the two optimizations produce very different commitments or transmission schedules.
  - Use and objectives of the financial market approach need to be more clearly outlined, with RUC process in a timeline to continue the conversation. Will this advantage resources that know their schedule while others do not?
  - PGP would like SPP to explore possibility of a single optimization so that reliability commitments are co-optimized with the financial energy market results, for example include an SPP forecast constraint and associated AS product.
  - This may achieve a similar goal while reducing risk to participants whose forecasts may differ from SPPs.
- Is there more background on similar constructs in other markets that could be shared from an education perspective?
- What is the role of virtual market participants in this approach, and how do we ensure they do not have unfair advantages?
- For the post DA process, the draft design document is lacking detail on the RTBM design assumptions. PGP recommends an education effort on the RTBM, including how it differs from the current WEIS and WEIM that many BAAs participate in today, and any process for superseding those.

Market power mitigation

PGP supports SPP's general market power mitigation framework. PGP recommends further analysis of how this may interplay with WRAP protocols, the voluntary nature of the market, and hydro default energy bid methodology.

- Given the potentially significant hydro inclusion in the market footprint, PGP recommends prioritizing hydro default energy bid analysis both in in the market power mitigation context and for general price formation logic, as this may be a deciding feature for some potential participants.

GHG accounting methods

PGP generally supports the design principles noted and the zonal framework. SPP has a good sense of the challenges to address in the design and has reflected a strong understanding of the tradeoffs of various approaches. Given the current lack of input from the Washington Department of Ecology, PGP recommends that the design document set forth a potential market design, explicitly highlight areas where regulatory input is needed, and note the impacts of different design choices in terms of emissions and price formation. PGP is open to helping facilitate further conversations with WA action agencies, including the Washington Department of Ecology when there is an opportunity to do so in the future. However, given that regulatory input is unlikely prior to the issuance of the final service offering, PGP recommends that the proposed approach remain preliminary until further discussions with state regulators are possible.

- PGP supports the continuing work with the GHG design team to further refine the proposal. For future discussions, stakeholders would be better supported to engage in the conversation if examples more clearly include LMP components at the different nodes and GHG shadow price. Please include some examples with price separation to help participants understand the true complexity of the issue and the role of outside resource participation.
- Any design will need to align with Resource sufficiency requirements, be scalable to additional loads in the GHG zone or additional GHG zones, minimize redesignation issues, align with policy guidance from the associated GHG zone. PGP supports further analysis in the areas already noted as challenging, including first pass solution criterion and interplay with congestion analysis.
- In stakeholder meetings there has been some discussion around whether it is appropriate for resources internal to a GHG zone to include GHG costs in their offers or submit GHG costs separately. Under either approach, it is important to ensure that internal resources are able to achieve GHG cost recovery (i.e., LMP + GHG price >= internal resource offer + GHG cost). It would be helpful for SPP to show some examples of both treatments demonstrating that full cost recovery is ensured in all cases.

Convergence bidding

PGP notes that while convergence bidding is considered a “best practice” of organized markets, research presented by SPP on virtual market participation achieving the goals of improved convergence and liquidity did not seem to affirm that any of the purported benefits were directly attributable to the allowance of virtual participation. PGP notes that a bilateral market has even less potential for strong convergence than an integrated forward market, so with the goal of incremental progress, a cautious approach is recommended.

Conclusions

PGP supports the progress made to date and looks forward to continuing to engage in the market design process. Given the significant list of topics remaining, additional workgroups and educational background may be required to improve the engagement process going forward.

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PPC Comments on SPP's Markets+ Draft Service Offering

The Public Power Council (PPC)[1] thanks the Southwest Power Pool (SPP) for the opportunity to submit comments on the Markets+ Draft Service Offering. PPC is supportive of the overall Markets+ framework described in the Draft Service Offering as a starting point in the next phase of Markets+ development. The document is a promising foundation and PPC looks forward to engaging on the next phase of Markets+ development to further refine the concepts captured in this service offering.

PPC appreciates the open stakeholder process which has been used to develop the Markets+ framework and SPP's receptiveness to stakeholder feedback and comments. We also appreciate the considerable efforts of SPP staff and involved stakeholders to create this initial service offering. We look forward to discussions on the next phase of Markets+ development and encourage SPP to share additional details about that phase at its upcoming November meeting.

PPC appreciates consideration of the comments below in development of the final service offering but acknowledges that many of the recommendations and questions in our comments will be best addressed in the next phase of Markets+ development.

Governance

PPC appreciates the continued refinements made to the governance structure by SPP. We would particularly like to acknowledge several changes made in direct response to previous stakeholder feedback – including creation of the Markets+ Independent Panel (MIP) and the potential for waiving fees for Markets+ stakeholders. PPC is generally supportive of the proposed Markets+ governance framework, with some additional recommendations and questions.

PPC is seeking additional clarification on when the Markets+ governance structure will be put in place. There are some elements of the governance structure which may be useful to stand up during the first phase of Markets+. In particular, we believe the Markets+ Participants Executive Committee (MPEC), workgroups and task forces – and potentially the MIP – would be elements to include in that first phase of Markets+. We ask that SPP address during its November

[1]PPC, established in 1966, is an association that represents the vast majority of consumer-owned electric utilities across five states in the Pacific Northwest. PPC's mission is to preserve and enhance the benefits of the Federal Columbia River Power System operated by BPA for consumer-owned utilities. PPC's members pay roughly 70% of BPA's annual $3.9M revenue requirement, in addition to owning their own generation and transmission facilities in the Northwest.

meeting the planned governance structure for Phase 1 and include details on the next phase of Markets+ development, including how decisions regarding draft tariff language will be made prior to submission to FERC and how market protocols will be finalized.

PPC appreciates the additional criteria provided in the draft service offering, which better define what constitutes "material" impacts to SPP. In the final service offering, we request additional information on the process for determining whether these criteria are met - which would indicate whether or not the SPP Board has authority over a decision - and what coordination between the Board and the MIP looks like in determining decision-making authority. Additionally, we request information on how an evaluation on decision-making authority will be communicated to stakeholders.

PPC is generally supportive of the proposed framework for the MPEC. Establishing a body of participants and stakeholders to inform the decisions of the MIP will be a helpful way to engage stakeholders. An important aspect of the MPEC is that its decisions will be advisory only, and that all final decisions related to Markets+ policies will be made by the MIP. It is also important that the Markets+ governance includes avenues for appeal if the MPEC does not choose to advance issues to the MIP. While PPC does not oppose inclusion of Markets+ Stakeholders in the MPEC, we question whether a separate committee of stakeholders is a more effective way to integrate stakeholder participation. Creation of such a group would allow the MIP to consider specific feedback from participants, stakeholders, and regulators separately when evaluating its decision. This may also help simplify potential challenges to incorporating Markets+ Stakeholders into the MPEC voting structure.

The proposed voting structure for the MPEC using three "sector" based voting groups is a reasonable starting point given the proposed MPEC composition, but the weighting given to each sector may need to be modified based on participation in Markets+. PPC also recommends that additional weight should be given to sectors where both load and generation is contributing to the market (COUs and IOUs under the current proposal).

PPC continues to support creation of a Markets+ States' Committee (MSC). It is important that state regulators are provided a meaningful role in the governance of Markets+. As self-regulated utilities, PPC looks forward to additional discussions on how representatives of publicly owned utilities may collaborate with state regulators to develop and improve Markets+ and the outcomes for end-use consumers regardless of whether they are served by an IOU or a COU.

PPC is supportive of establishing the standing workgroups as described in Section 3.4.1.5 of the draft service offering – the Operations & Reliability Workgroup, Markets Workgroup, and Seams Workgroup. We request that, at its November meeting, SPP address whether these workgroups will be stood up for Phase 1, or whether the existing workgroups which have been in place during the initial Markets+ discussions will continue. We also support ad hoc creation of new task forces. The proposed task force on coordination between Markets + and WRAP is an excellent example which we enthusiastically support.

Appointment to working groups through MPEC Chair nomination and approval by the MPEC is potentially workable, but an appeal process may be needed for participants or stakeholders that feel they have been inappropriately excluded from a workgroup where their interests cannot be sufficiently represented by another workgroup member. An alternative would be instituting a sector nomination process to allow each sector to self-select representatives on the working groups.

As included in the draft service offering, PPC strongly supports the proposed governance review no later than three years after Markets+ launches. This will be vital for ensuring that the governance structure is working as intended and is appropriate for Markets+, which may continue to evolve from this initial service offering.

Relationship to Resource Adequacy Programs and Confidence in Transfers

Conceptually, PPC supports applying a common Resource Adequacy (RA) standard to Markets + participants. This requirement, in conjunction with the inclusion of a must offer obligation, initially appears to be an efficient way to avoid the need for a Resource Sufficiency test. If feasible, this approach could significantly simplify the Markets+ framework. We look forward to additional discussions on potential impacts of this approach.

PPC supports the WRAP as the foundation for this RA standard, as well as enabling non-WRAP participants to participate in Markets+ through meeting Western Resource Adequacy Program (WRAP) equivalent standards. PPC looks forward to further discussions on whether Markets+ participants – not participating in the WRAP but meeting the same requirements – should have access to dispatches of capacity "held out" through the program. PPC seeks to ensure that the benefits of the WRAP are consistent with the obligations and responsibilities of participating in the program. This means to the extent that entities "meeting common standards" of the program are not taking on the same obligations and potential for financial penalties as participants in the program, there could be inequities from allowing those entities the same access to diversity benefits and capacity made available through the WRAP.

PPC believes this question is one of many related to how the relative priority of different types of market transactions are resolved through the market optimization. For example, in the event the market cannot economically find an optimal solution, which resources and loads receive market awards? PPC believes it is appropriate to begin discussing this question of how the relative priority of different types of transactions are or are not included in the market optimization. This issue is critically important to PPC members who are preference customers of BPA and who have a statutory right to exercise a preference right to BPA's federal generation.

Congestion Rent Allocation

PPC supports continued dialogue on the appropriate design elements of a congestion rent allocation. Further developing and clarifying the proposed congestion rent allocation should be prioritized in the first months of the next development phase. Beyond the questions identified by SPP in the draft service offering document, additional discussion is needed to better define what transmission is eligible for congestion rent. For example, in the Northwest, long-term firm Point-To-Point (PTP) (7F) is regularly redirected or resold on the short-term firm basis. Should congestion rent be allocated to the short-term firm redirect or the parent long-term firm request? PPC also supports further discussion on whether a tiered approach to congestion rent allocation is warranted to address the potential over-dilution of congestion rent allocated to transmission rights holders. In Phase 1 of Markets +, additional discussion on real-time congestion rent allocation and frequency and eligibility of a Transmission Service Request (TSR) submittal for congestion rent will be valuable. We look forward to exploring these questions in the next phase.

Day-Ahead Market Design

PPC supports continued exploration of the "option 2" Day Ahead (DA) market structure that includes a reliability-based, physical resource commitment which occurs prior to or concurrently with a financial day-ahead market run. PPC believes this approach may create efficiencies beyond the "option 1" financial market run first approach, and we look forward to additional discussion on how this approach could be implemented. Numerical examples of how the "option 2" optimization is formulated, and the settlement impacts of this approach would be very valuable to help stakeholders consider the benefits and potential workability of this approach. We appreciate SPP's willingness to explore the option 2 approach and develop novel solutions for Markets+.

PPC believes there may be opportunities to improve the efficiency of how available transmission can continue to facilitate imports, exports, and wheel-through transactions across the Markets+ footprint in real time. PPC understands that after the completion of the day-ahead market optimization, Open Access Transmission Tariff (OATT) providers will be able to continue to sell OATT service. We also understand that OATT transmission reservations would be required to wheel-through, import, or export from the Markets+ footprint in real-time. PPC would like to explore facilitating these transactions through the Markets + framework, leveraging flow-based calculations to efficiently utilize transmission capacity, and charge a hurdle rate that would compensate all legs of OATT transmission required. This approach would more effectively facilitate imports, exports and wheel-throughs as compared to requiring individual participants to purchase OATT service from individual providers in real-time. The hurdle rate would also ensure that OATT providers would still be made whole for the transmission used.

PPC supports a cautious approach to incorporating virtual bidding into Markets +. Given the unique nature the Markets +, PPC is inclined to add convergence bidding functionality at some time after Markets + is launched. Whether or not convergence bidding is adopted at go-live, PPC requests that SPP evaluate the impacts of including or not including convergence bidding after the market is operational.

Seams

PPC supports standing up the proposed Seams Workgroup as part of the next phase of Markets+ development. Management of market-to-market seams will be a largely new concept in the West and additional focus on developing these policies will be important. PPC believes it may be a helpful exercise to provide an overview of SPP's current seams agreements in its Eastern RTO to inform the efforts of the Seams Workgroup.

Phase 1 Structure and Participation

PPC requests additional information on the structure of Phase 1 Markets+ development, along with additional details on "participation" in that effort. As described in the "Governance" section of these comments, PPC has several questions around how decisions will be made during Phase 1, as well as what elements of the proposed governance framework will be used to support Phase 1 development. While PPC understands SPP plans on hosting a meeting in early November to address Phase 1, these comments reflect PPC's initial questions on elements of that process.

We also ask that SPP provide additional information on what "participation" in Phase 1 looks like. Specific questions related to participation include:

- What entities are eligible for participation? Is participation limited to Balancing Authority Area services (BAAs) or transmission owners that would participate in the program? Are Load Serving Entities that do not own their own transmission or generation eligible to participate? Are stakeholders eligible to participate in Phase 1?
- How will costs be allocated among participants in the program? If stakeholders are allowed to participate, would they be charged the $5,000 fee that is proposed for Markets+?
- Will entities that are not funding participants of Phase 1 be able to participate in the Markets+ development process? What will be the difference in the way that funding participants and non-participants provide input into Markets+ designs?

We hope that SPP can address as many of these questions as possible at its upcoming November meeting to better inform whether potential participants and stakeholders choose to fund the next phase of Markets+ development.

Conclusion

PPC appreciates the opportunity to engage with SPP staff and stakeholders as part of this process. We are very encouraged by the progress made in the proposal to date and look forward to continuing to add to and refine the proposal as we move towards SPP's initial Markets+ service offering.

PSCo's Comments on Markets+ Draft Service Offering – October 28, 2022

Xcel Energy-Colorado ("PSCo") appreciates the opportunity to provide comments on SPP's Markets+ Draft Service Offering which was released on September 30, 2022. PSCo also thanks SPP for fostering an open and collaborative process for stakeholders to contribute to the development of the Markets+ offering. Below are comments on specific sections of the document and to avoid confusion, we've referenced the page numbers.

1. **Governance**

   PSCO generally supports the proposed governance structure for Markets+. The Company appreciates several recent changes to the governance proposal addressing our concerns regarding the ability for the MIP to select its own chair, clarification processes related to Working Group development in 3.4.1.1, and creation of that Standing Committees as identified in 3.4.1.5.

   a. **Section 3.2.2:** PSCo reiterates its request that the SPP Board member selected to participate on the MIP be required to have western experience.

   b. **Section 3.3.1.4:** PSCo originally advocated for a two-sector voting structure comprised of Balancing Authority Participants (BAP) and Other Participants with a 50/50 weighted voting structure in order to recognize the reliability responsibilities BAPs will carry in Markets+. Recognizing the representation concerns raised by other stakeholders, the Company can support the proposed three-sector voting structure and believes this modification along with the annual membership fee waiver for non-profits more than adequately addresses concerns raised by other stakeholders.

2. **Market Design**

   PSCO generally supports the proposed market design features for Markets+ and recognizes that many of the finer details missing from the draft offering will be resolved in later phases of Markets+ development. PSCo focuses the comments below on issues where modifications should be made to current design and to provide feedback on questions asked by SPP to guide future development efforts.

   a. **Page 29:** Regarding Flexibility Reserves
      PSCo recognizes that further study and analysis will be undertaken to refine the Flexibility Reserves products. As more detailed design is evaluated, the Company encourages design elements that will enable Flexibility Reserves to be carried across BAAs (to the maximum extent practicable) in order to improve the economic market solution.

   b. **Page 46:** Congestion Rent Allocation
      PSCo continues to oppose the SPP proposal to use all TSRs as the basis for the congestion allocation and believes rents should be allocated based on scheduled TSRs.

The proposed approach will likely create a dilution effect, increasing overall congestion exposure to transmission customers compared to traditional mechanisms used in the RTO/ISOs for financial congestion rights.

As stated in our September 16 comments, the formula that SPP proposes provides more allocation (in dollars) to more congested areas, but the volume of TSRs eligible for allocations, regardless of feasibility during the operating timeframe, will likely spread the congestion rent to such an extent that customers may be left with pennies on the dollar relative to the congestion costs they paid into the market.

Further, if facilities are out of service that would limit the use of the transmission service on previously granted TSRs, SPP's design ignores those limitations and would apply the congestion rent allocation to the TSR holders for the full amount of the reservation. This approach also drives dilution of the allocation and increase the socialization of the congestion costs associated with the facilities out of service.

Addressing the questions identified by SPP starting on Page 47:

- The congestion rent allocation cap for network customers should reflect daily or perhaps hourly loads
- The network customer should supply a resource plan in advance of the day-ahead market
- Congestion rent should first be allocated up to the full value of priority seven TSRs followed by priority six TSRs for any remaining congestion rents
- PSCo supports further examining categorization of transmission rights into zones

c. **Page 50:** Regarding Convergence Bidding
PSCo advocates to delay implementing convergence bidding in order to let the market mature before implementation instead of incorporating it into the initial Markets+ design.

d. **Page 51:** Regarding GHG
PSCo commends SPP for its efforts to develop a GHG pricing and dispatch mechanism that will accommodate multiple GHG zones throughout the Markets+ footprint and appreciates the development of a baseline approach to minimize MW-Redesignation. As state-level GHG policies will continue to evolve, PSCo urges SPP to maintain flexibility in design to ensure market mechanisms can be applied to GHG pricing programs that differ from traditional cap and trade programs. These could include the use of a shadow price for supporting re-dispatch to manage carbon emissions for specific states, areas, or utilities. PSCo also reiterates its interest in better understanding if SPP can apply the GHG zone structure to a more granular level than a state. For example, can it be applied to a BA level? Or an individual system?

e. **Page 63:** Regarding Seams

PSCo agrees that seams will continue to be a critical issue to address in Markets+ design process and supports the formation of the Seams Working Group to address these concerns.

3. **Transmission**

PSCo appreciates added detail regarding the tasks the Markets+ Transmission Working Group will address; however, we reiterate our request that SPP propose rules, governance, participants, and appropriate structure for this important group to make sure expectations are understood. This group and related details should be codified and should be included in Section 3.4 of the Governance material.

a. **Page 65:** Regarding Market Transmission Service (MTS)
PSCo supports MTS being charged to all transactions (generation and load) clearing in the real-time market. Charging the rate to both load and generation will preclude any free ridership issues from arising. PSCo believes the MTS should be a single rate applicable to all hours. Having a rate that changes hourly will create uncertainty for generation offers. The Markets+ Transmission Working Group should also evaluate how often to update the MTS rate (i.e., yearly, or monthly) along with a process to true-up from time to time.

4. **Market Settlements**

PSCo reiterates its support for direct settlement between SPP and participating entities – instead of relying on the BA like in the CAISO EIM/EDAM design.

5. **Market Monitoring**

PSCo generally supports using SPP's existing market mitigation logic in the Markets+ design as well as selecting the SPP MMU as the monitor for Markets+. Leveraging the existing systems, processes, and staff who are already familiar with the logic and SPP market designs should reduce overall costs of the service offering and simplify implementation.

6. **Stakeholder Relations**

PSCo does not offer comments at this time.

7. **Implementation**

PSCo does not offer comments at this time.

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Comments of Renewable Northwest on SPP's Markets+ Draft Service Offering

Governance

Renewable Northwest ("RNW") commend SPP for making improvements to the governance proposal. The current proposal is moving closer to the type of governance model expected in the West: an independent, transparent process that allows for participation by a wide variety of stakeholders. However, there are still several critical improvements that SPP should make before the proposal can be considered adequate for western market expansion.

MIP Chair

RNW supports the change to allow the MIP to elect its own chair instead of requiring that the MIP chair be the SPP Independent Director assigned to the MIP. RNW further recommends that the SPP Independent Director appointed to the MIP should transition to a non-voting, advisory position after three years. Allowing voting representation of an SPP Independent Director on the MIP dilutes the MIP's autonomy and independence. Phasing this into a non-voting advisory role after three years will provide the oversight and consistency SPP is seeking as the program evolves, while also preventing conflicts of interest when MIP issues are appealed to the SPP Board. When the SPP Director position transitions to a non-voting advisory role, an additional independent, voting board member can be nominated by the MIP Nominating committee.

MIP Nominating Committee (NC)

The purpose of the NC is to ensure broad stakeholder input and buy-in on one of the most critical pieces of the Markets + governance structure. In order to maintain both independence in selecting a slate of MIP candidates, the NC's authority and structure cannot be compromised by petition's for write-in candidates who have not gone through the detailed screening process of NC interviews. Allowing this override of the NC's authority dilutes the value of the committee and undermines the process of selecting an independent slate of candidates.

RNW is pleased to see the proposed governance structure calls for an NC made up of one sector one vote. This model has worked well in other market operations including, the CAISO EIM and most recently the Western Power Pool. This model provides the most robust, independent, defensible process for selecting board members. The election of the first slate of MIP members will require a unique process, which should strive for a final decision made at the committee with the most broad stakeholder representation. At this initial stage, the MPEC should be voting on the initial slate of MIP members as the MPEC, as currently proposed, includes one representative from each Markets+ market participant and Markets+ market stakeholder, representing the full breadth of program stakeholders. After the initial MIP is established, the MPEC should no longer have authority to vote on MIP candidates. The MIP should have the authority to approve or reject future candidates and MIP member renewals based on a recommended slate brought to them by the NC. IF the MIP rejects the NC's recommendation, the MIP should provide the NC with an explanation of deficiencies and the NC will submit an alternative slate of candidates.

Market Design Proposal Process

As currently proposed, SPP, the Markets+ State Committee, the MPEC, or any designated working group, committee, or task force established by the MPEC may make proposals for market design system or process enhancement proposals to the MIP. It would be more efficient for the MIP if these proposals were to go through a standing working group similar to the Program Review Committee ("PRC") in the WRAP, with approval by MPEC and the Markets+ State Committee prior to MIP consideration. This would also strengthen the Markets+ State Committee role in decision making, rather than relegating it to a strictly advisory role. One of the proposed standing committees is the Market Working Group, whose responsibilities and sector representation could be expanded to be more like the WRAP's PRC.

Fee Waiver

RNW appreciates that SPP is including a waiver of the annual Market Stakeholder fee for eligible entities that are nonprofit organizations under the Internal Revenue Code. RNW encourages SPP to be transparent about how an entity is determined "eligible" if there are criteria in addition to that entity being a nonprofit as defined for federal tax purposes. Additionally, SPP should clarify if the waiver is ongoing once granted (unless the entity's tax status changes) or if an entity must apply for the waiver every year. RNW suggests that the waiver should not require annual approval, as, even with the waiver, participation as a Stakeholder will require nonprofits to dedicate staff and resources that may need approval in budget cycles and strategic plans longer than one-year timeframes.

RNW also appreciates the expansion of the role for Markets+ Market Stakeholders to include participation in MPEC. The "Independent" category for voting on MPEC as proposed will likely be a large group with more diverse interests than the IOU or Public Power groups. Markets+ should consider and allow for further division of the "Independent" group into groups with more similar interests if it becomes too large and divisive of a group.

Review of the governance structure

RNW supports the governance review proposal in Section 4.0 to review the governance structure no later than three years or upon the MPEC's request.

Decision flow diagram

At the in person meeting in Portland on August 9-10, during the second day of the governance design discussion, it was agreed that a flow chart identifying the various committees and the flow of information and decision making would be provided in a subsequent draft. This is a useful tool to see how the decision making and appeal process works and the infrastructure of the governance proposal. RNW requests that before a draft tariff filing is prepared that such a schematic is provided to stakeholders for review and comment.

Participation in Design Phase I

RNW requests clarification of which entities defined in the Markets + governance proposal will have the ability to participate in the next phase of governance and program design. During the next phase, the proposal will be modified into a tariff. It is our expectation that the waiver of the membership fee be offered to entities meeting the non-profit criteria to participate in design phase I. Public interest groups should not be required to pay a fee to simply be allowed an opportunity to participate in the design of a program of which they are a defined class of stakeholders. We are hopeful that this will be clarified prior to kicking off design phase I.

Program Design

It is difficult to provide comments on the program design at this time, as many changes will likely be made in Phase I. RNW does propose that, as the program design develops, SPP keep the following principles in mind:

- Markets+ should maximize efficient use of the transmission within its footprint while minimizing pancaked rates.
- Seams issues between Markets+ and other markets (CAISO, EDAM, WEIM) as well as with non-participating bi-lateral agreements should be minimized. While we recognize the ongoing challenges with CAISO's governance, CA still represents a large market in the West that has close transmission ties with many entities that may ultimately participate in Markets+. Additionally, some entities in the West, such as BPA, own much of the transmission in the Northwest and may not join a market immediately. Markets+ should be designed in a way that does not create a hard seam between Markets+ participants and any adjoining non-participants.
- Renewable resources and storage will be the predominant resources in the Northwest by 2030-2040 if state requirements and utility goals are met. The Markets+ program design should properly value capacity of renewable resources and storage and should allow for independent power producers to participate in the market without creating unnecessary rate barriers.
- Greenhouse Gas emissions will need to be accurately accounted for in a way to accommodate multiple state requirements. The accounting should be done in a way that does not shift emitting resources to states without GHG requirements and should also not create additional market participation burdens, including financial, based on the existence or lack of a statewide GHG accounting requirement.

Respectfully submitted this 28th day of October 2022,

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Seattle City Light Comments on the Markets+ Draft Service Offering Proposal

Seattle City Light (SCL) appreciates the continued effort by SPP to progress the Markets+ design forward and the opportunity to provide comments on the Draft Service Offering Proposal.

On the whole, SCL is encouraged with the foundational elements SPP is contemplating in the creation of a Day-Ahead market. From the Draft Service Offering, the skeletal structure seems to be in place, but design details are lacking in the document and numerous areas exist that will require additional fleshing out prior to being able to fully evaluate the offering for potential benefits of participation. The areas discussed below are of particular interest to SCL that we want to take the opportunity to highlight and encourage additional design work around.

Resource Adequacy

WRAP

SCL supports the inclusion of a Resource Adequacy requirement as part of the Markets+ design as well as utilizing the WRAP as the Resource Adequacy Program, pending FERC approval. SCL isn't opposed to allowing non-WRAP member Markets+ participants to make an independent showing that they are meeting an equivalent reliability standard, however, absent a resource sufficiency evaluation, non-participation in a common RA program will introduce additional risk of parties coming to the market with insufficient resources and will need to be tightly monitored. Additional detail on how non-member WRAP entities would demonstrate that they're meeting the same reliability standard, and the binding nature of that obligation, is needed. Without an additional RS evaluation, mandatory participation in WRAP or a common RA program by all participants would likely be necessary to adequately ensure actual resource availability.

Must-Offer Quantity

The must-offer quantity would add additional assurance that RA will be met by all parties and SCL is in favor of combining this requirement with an RA program. The proposal notes that additional work with stakeholders will need to take place to discuss these concepts further. Because the proposal is light on details for how the RA program would function, it is difficult to be able to provide meaningful feedback. However, SCL would encourage discussion and creation of mechanisms to be developed around resource adequacy showings and the resultant consequences of either financial penalties and/or an inability to participate in the market for the time period in which RA was not met by a participant.

Additional Resource Sufficiency Tests

While the inclusion of an RA requirement with a tandem must-offer quantity should give significant surety of resource availability in the market, even the best designed plans don't operate perfectly 100% of the time. To help bridge any potential shortfalls of an RA requirement, and to ensure an accurate view of resource availability in the day ahead and real-time timeframe, SCL encourages consideration of including a Resource Sufficiency test. WRAP is untested and while it should work well, there is no harm in imposing a final RS test to ensure that participants' resources are actually available when needed. There is beauty in the simplicity of just having a singular RA requirement and an overcomplicated design with unnecessary tests could result in market inefficiencies, but SCL suggests a balanced approach with a final RS test to fully guard against insufficiency. An RS test design should result in transparent, predictable requirements which facilitate participant efforts to plan for effective and reliable market participation.

GHG

SCL has both ambitious carbon goals of its own and is also subject to relatively new WA regulations around GHG compliance, such as CETA and CCA. These dual forces make including a thoughtful, well-designed GHG program critical to the evaluation of a Day-Ahead market.

Tracking and Reporting

Because the WA programs are new, and other states will likely continue to adopt additional regulation of GHG over time, it will be important to build in flexibility into the market design to be able to provide the necessary data that each state requires to ensure market participants are able to comply with each entity's state regulations. SCL appreciates that SPP is planning to work with stakeholders to determine the necessary data and reporting entities and the associated Business Practices that will govern tracking and reporting.

Pricing

The proposed design includes a "zonal approach" with zones denoting states with GHG regulation and pricing to serve the zone categorized into three resource specific categories: GHG zone internal generation, specified-source imports and unspecified-source imports. SCL supports the classification of these different categories of resources to ensure the emission rate for each is accurate.

SCL also supports the modeling of a two-pass solution to establish a baseline for measuring incremental energy in an effort to minimize supply redesignation and would encourage an exploration of how other organized markets, specifically the CAISO, have dealt with this issue in their market design.

The SPP proposal lists the following considerations that will continue to be discussed and incorporated into the stakeholder process:

• Minimize total production costs with GHG costs considered
• Provide a framework for any capacity to be dispatched to the zone with GHG regulation
• Properly account for specified and unspecified MWs serving the zone
• Implement a solution that meets the intent of GHG policies
• Ensure that GHG costs associated with imports into the GHG zone only apply to load in that zone

SCL agrees that these are important guiding principles, but the devil is in the details and designing a GHG program that achieves these is no small task. A detailed GHG design will need to be part of the final offering for SCL to determine its ability to join a Day-Ahead market while still complying with its GHG regulatory requirements. Given the large body of work that this will entail, SCL encourages an intensive push to fully develop a detailed design during Phase 1. As part of the continued GHG design development, SCL recommends considering the additional following issues:

• Co-optimization of GHG and energy costs with equality of treatment across GHG zones
• Constraints and relaxation of constraints surrounding GHG zonal requirements
• Structures for reflecting ex-market resource GHG commitments into the participation model
• Treatment of differing resource technologies
• Use of publicly available data to establish cost basis
• Publication of necessary market data for participants to demonstrate compliance with GHG reporting requirements

Fast Start Pricing

SCL fully supports the inclusion of fast start pricing into the Markets+ design and notes that such inclusion is consistent with FERC's statement that "a lack of fast-start pricing practices may result in market prices that fail to accurately reflect the marginal cost of serving load." Designing practices around fast start pricing that take lessons from FERC directives from other organized markets would provide a solid footing to develop specific rules governing fast start pricing. Because the proposal does not yet specify how fast start pricing would be designed, SCL recommends working through how and when fast-start resources are decommitted, and how any uplift charges due to the pricing run are assessed.

It is encouraging that the Draft Service Offering is contemplating the following two principles for fast start pricing: 1) Relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero for the purpose of calculating prices and 2) Incorporate commitment costs, i.e., start-up and no-load costs, of fast-start resources in energy and flexibility reserve prices. Reflecting the marginal nature of fast-start commitment decisions is key in intelligent price formation, and SCL supports these concepts.

SCL also supports allowing resources to offer in three parts: the cost to start the resource, the cost to maintain output at the minimum dispatchable limit and an energy offer curve representing the cost to produce incremental energy above minimum output.

Additionally, SCL encourages discussion of the following topics for pricing of the resource commitment:
• the ability to accurately reflect resource startup, minimum load and energy costs of a variety of resource technology types
• a structure to enable the accurate reflection of opportunity costs, water availability and hydrological realities to allow effective and reliable participation of hydro resources

Scarcity Pricing

In addition to fast start pricing, SCL supports the inclusion of other scarcity pricing elements into the Markets+ design. The two elements proposed are 1) that the appropriate demand curves for Markets+ be derived based on the cost of the next action to resolve a shortage as a starting point during the next phase of detailed market design and 2) that a required 'check and adjust' processes be established in the Markets+ tariff, requiring annual review of the scarcity pricing model performance. SCL believes that not only should scarcity pricing reflect the cost of the next action to resolve a shortage, but also the value that additional capacity would provide via increased reliability at that time. While 'check and adjust' processes are valuable, particularly in new and developing markets, the value of regulatory certainty should be acknowledged. Additionally the elements and measures of performance in the annual review should be transparent and both developed and agreed upon by stakeholders.

In addition to these two primary elements, it will be important to consider and incorporate interaction with resource adequacy (i.e. does the projected planning reserve margin factor into the annual review), the presence of a price or offer cap, and the method of inclusion of reliability actions into the scarcity pricing model design.

Conclusion

The Draft Service Offering provides a summary description of a potentially successful Day-Ahead market design. The foundational elements have been established, but as the document notes the detailed specifics are going to take a significant time investment as numerous areas of design are still in the conceptual realm. The timeline of 21 months for Phase 1 completion may be necessary but the process must remain focused. To help ensure against the design work starting to lag, SCL encourages including quarterly milestone check-in points to assess progress. If enough progress has not been made at these check-in points, then the schedule should be adjusted or other mitigation measures implemented to ensure that a fully fleshed out design can be presented to potential participants at the end of the 21 month period.

Thank you for the consideration of SCL's feedback and we look forward to continued participation in this process.

Delivering water and power®

October 28, 2022

TO: Southwest Power Pool Western Energy Services (marketsplus@spp.org)
FROM: Josh Robertson, Director, Energy Market Strategy
SUBJECT: SRP comments on SPP's Markets+ Draft Service Offering

GENERAL comments:

Salt River Project Agricultural Improvement and Power District (SRP) appreciates Southwest Power Pool's (SPP) collaborative approach to creating a western day-ahead market and the opportunity to submit the following comments on the Markets+ (M+) draft service offering. SRP is encouraged by and generally supportive of the draft service offering. SRP also respectfully encourages SPP to provide additional details and clarification on the following topics in the November 15-16 stakeholder meetings and/or the M+ final service offering.

GOVERNANCE comments:

SRP is generally supportive of the SPP M+ governance proposal. In addition to the SRP governance comments below, SRP supports the governance comments made by Arizona Public Service, Tucson Electric Power, NV Energy, and Public Service Company of New Mexico.

SRP has several questions and would like clarification on the following:

- When would the M+ governance proposal become effective? Clarifying when all or portions of the governance proposal would be effective would provide further clarity as to the implementation timing. Implementing some or all of the proposed M+ governance structure could provide structure in developing the M+ draft Tariff.
- SRP assumes and requests clarification that the MIP will govern all elements of M+, including Resource Adequacy (RA). For example, SPP M+ proposes utilizing the Western Power Pool Western Resource Adequacy Program (WRAP) for its RA requirements; however, if market conditions necessitate a change to the RA construct, that change should ultimately be governed by the MIP.
- Geographic diversity should be included throughout the M+ governance construct. Geographic diversity (northwest and desert southwest each to be represented and have a vote) will be critical to any working group, nominating committee (NC), MPEC, MIP or other working group representation within the M+ governance construct. Given the diversity in generation types and load requirements between the northwest and desert southwest, as well as the northwest being dominated by public power, geographic representation will be important for entities such as SRP.
- While SRP is generally supportive of the SPP Markets+ governance proposal, SRP recommends that SPP incorporate additional flexibility in its MPEC proposal in order to account for adequate regional diversity and adopt a mechanism to reassess the efficacy of the three-pronged voting structure once the pool of market participants is known. SRP encourages SPP to evaluate the proposal of NV Energy and any others that attempt to ensure that there is adequate and appropriate regional representation within the Markets+ governance structure.

- The governance proposal does a good job defining “business” vs “calendar” days, except for several instances that need to be clearly defined in the governance proposal. Additionally, the entire M+ service offering should clarify if market time steps are “business” vs “calendar” days. At a minimum, please clarify type of days for:
    - 3.2.4 MEETINGS: “Agendas for regular meetings will be publicly posted no less than seven days prior to the meeting.”
    - 3.3.1.3 MEETINGS: “. Agendas for regular meetings will be publicly posted no less than seven days prior to the meeting.”
    - 3.7 APPEALS TO THE MPEC AND THE MIP: “…. submit an alternate recommendation, including a recommendation for inaction to the MPEC within seven (7) days after the meeting following such Working Group or Task Force action or inaction.”
    - 3.7 APPEALS TO THE MPEC AND THE MIP: “….and submit an alternative recommendation, including a recommendation for inaction to the MIP within seven (7) days after the meeting following the MPEC denial.”
- Section 3.2.2 COMPOSITION AND QUALIFICATIONS – This section states that members of the MIP “shall not be limited in the number of terms he/she may serve.” In general, SRP supports term limits and supports the use of term limits for the M+ working group chairs. What is the logic behind lack of term limits for MIP? Revolving term limits could allow for new ideas/leadership to percolate. For example, the WPP WRAP has a limit of two 3-year terms, and the California Independent System Operator (CAISO) Western Energy Imbalance Market Governing Body has a limit of three 3-year terms for each Governing Body member.
- Section 3.2.3.2.1 Composition of the NC – SRP would like each sector to be defined for clarity. SRP encourages SPP to incorporate geographic diversity into some of the NC sectors. For example, in WRAP, some sectors have two representatives to provide geographic diversity, such as the Resource Adequacy Participant Committee (RAPC)/Participants Publicly Owned Utilities. This sector has SRP as the southwest representative and Chelan PUD as the northwest representative.
- Section 3.2.3.2.3 Voting Structure for NC
    - Is the NC voting and process used in M+ the same process used in SPP, or is it novel? SRP is concerned that the NC voting does not allow for proxy voting and encourages SPP to include proxy voting for the NC. Proxy voting is allowed and was successfully utilized in the WPP WRAP NC.
    - Given SRP’s experience on the WPP WRAP’s NC, SRP encourages that NC meetings be closed until a final draft slate is identified because of the sensitive nature of the deliberations. NC meetings tend to include discussion of confidential information about candidates. Having open meetings of the NC could stifle honest discussion of the candidates.
- Section 3.3.1.1. Composition of MPEC – Proposal states: “Each M+ market participant and M+ market stakeholder shall appoint one representative to the MPEC.” Is this similar to the WRAP RAPC / Resource Adequacy Operating Committee (RAOC) design where each entity has more representative? Would voting be one entity, one vote? Please clarify.
    - More discussion needs to occur regarding the MPEC voting structure.
- Section 3.4.1.4 VOTING STRUCTURE – The governance language should expressly include the ability for any minority opinion to be heard and recorded in the minutes for

working groups and committees and communicated to the MPEC by the Chair of the working group or committee. Given the geographic diversity of the potential M+ footprint, the minority opinion would be important to communicate.

- Section 3.4.2 - Ad hoc task forces stood up by MPEC – SRP supports task forces to be formed for the purpose of a limited scope with a well-defined end point. However, SRP would like more information regarding the process for adjourning or dissolving an ad hoc task force. How is it determined that the task force has completed the scope of its work? Is this at the discretion of the MPEC chair, just as the creation of these task forces is? Please add this information.
- Section 3.7 – Appeals to the MPEC and MIP – SRP would like more information on the processes or mechanisms for what would happen should the MIP or MPEC not move on an appeal in a timely fashion? SRP understands that the MIP can affirm the (in)action, reverse it, or remand issue back to working groups, but we would like to know if there are contingencies in place should the MIP fail? Additionally, what would be considered a reasonable timeframe? Is a month reasonable to resolve an appeal?
- Section 4.1 Governance Review:
    - This section identifies examples of changed governance circumstances which include “voting structure changes: Findings and a request by the MPEC that participation and voting experiences suggest that changes in voting structures are needed.” Would a majority vote of the MIP be required to conduct a governance review? Could one entity suggest this voting structure change, or would critical mass be needed to do so?
    - Additionally, the M+ proposal states: “Any modification to M+ governance requires a super majority (4/5 vote) of the MIP.” Is that reasonable? This could be a barrier to potentially good and needed changes to the M+ governance structure. Perhaps a majority vote (3/5) of the MIP to move forward with any governance changes is more reasonable.

MARKET DESIGN comments:

- <u>Timelines:</u> Previous comments submitted by SRP regarding the M+ Market Design and Transmission Availability Working Draft encouraged SPP to focus on aligning M+ timelines with timelines currently used throughout the west to minimize the need for changes in practices. SRP also suggested consideration of multiple time zones within the M+ footprint and the potential for impacts during daylight saving time. SRP requests SPP and stakeholders consider the following during development of M+ timelines:
    - SRP recommends the bid submission window end at 10:00 PPT to align with SRP’s current activity in its bilateral transactions, which starts at 5:00 PPT and officially ends at 9:00 PPT. This will allow adequate time to reestablish SRP’s position for the next day.
    - SPP is proposing to communicate Residual Unit Commitment (RUC) results at 16:15 PPT. Current day-ahead trader working shifts typically end at 16:00 PPT and the proposed deadline of 16:15 PPT would require traders to watch RUC in real time, rather than after results are published. SRP encourages the SPP to publish market results and RUC at 13:00 PPT to ensure 15:00 PPT tag creation deadlines are met.

- <u>Reserve Zone</u>: SRP requests that SPP provide clarification and define *reserve zone*. Page 23 of the Draft Service Offering states, "Flexibility reserve procured costs are allocated and collected on a reserve zone basis." Page 43 indicates that after the M+ footprint is known, participants may elect to go through a study effort to determine the need for reserve zones. These statements seem inconsistent.
- <u>Resource Participation Model – Demand Response (DR)</u>: SRP requests that SPP provide additional detail on DR requirements for participation, including clarification on whether the model will allow aggregation of DR. Additionally, SRP encourages the SPP to clarify how DR that occurs in real-time will be monitored for deliverability.
- <u>Resource Participation Model – Joint Operating Unit (JOU)</u>: SRP supports the proposed options for participants to select in effort to accommodate the operating conditions of a JOU.
- <u>Resource Participation Model – Variable Energy Resources (VER)</u>: SRP requests clarification on SPP's proposal for VERs. SRP prefers that a VER run at maximum output, even if the forecast is lower, except in cases when the market is dispatching it. Please clarify if that is what SPP is proposing in the Draft Service Offering. SRP supports VERs being dispatched in real time.
- <u>Resource Participation Model -- General</u>: SRP requests that SPP clarify if resources other than combined cycle may have multiple configurations that correspond with physical operations to best reflect unit characteristics. SRP recommends extending this model to other resources, such as coal units with multiple mills.
- <u>Resource Participation Models</u>
    - <u>Hydro Resources:</u> SRP encourages SPP to adopt a grouped hydro resources participation model to account for operating characteristics of a whole river system.
    - <u>Gas-limited Resources:</u> SRP requests SPP provide a participation model that provides the ability to limit gas resources to a daily limit, based on the gas day, for a group of resources with the same gas constraint. SRP recognizes challenges between the timing of the gas day and electric day and encourages SPP to leverage central time for the purpose of the gas submittal schedules. SRP also agrees with NV Energy's suggestion for exploration of the reliability of the outputs from SPP's multiday informational study and further development of must-offer requirements with consideration for gas procurement. Additionally, SRP requests SPP identify and address any potential seams issues that may arise due to increased gas trading with California entities.
- <u>Fast Start Resource Pricing:</u> SRP supports SPP's proposal to include fast-start pricing and encourages further discussion on this topic.
- <u>Bid Cost Recovery:</u> SRP requests more discussion in Phase One on how the bid cost recovery mechanism will ensure that participants recover costs to start or run resources.
- <u>RUC</u>: SRP requests clarification on the RUC process horizon. On page 33, the proposal states, "The RUC processes begin with hourly granularity assessments of the existing resource commitments, transitioning to a shorter-term, more granular study". Does this indicate that the optimization horizon for RUC is only one hour? Many participants will

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have resources with long startup/transition/minimum up or down times that will require a long study horizon for commitments. SRP recommends ensuring that the horizon be long enough to accommodate resources required for reliability.

- M+ RA Requirement:
    - SRP supports the proposal for M+ to incorporate a common RA requirement and understands that stakeholders will likely select WRAP as the common RA framework. As stated in our governance comments, SRP recommends that the MIP govern the RA requirement for M+. For example, if WRAP evolves in a way that no longer supports the best interest of M+ participants, the MIP should have the authority to change the M+ RA requirement.
    - SRP also recommends that the next phase of the market design prioritizes efforts towards examining the need for common participation in the WRAP program and supports the creation of a task force to facilitate the coordination between WRAP and Markets+.
- Bilateral Market: SRP prefers a framework that allows entities to continue to participate in the day-ahead bilateral market. Typically, this is from approximately 5:00 AM through 9:00 AM PPT and 6:00 AM through 10:00 AM PPT Monday through Friday. SRP recommends allowing an entity to establish its M+ day-ahead position *after* this timeframe. Then the M+ three- to four-hour process of completing and posting the day-ahead Market solution would take place.
- Ancillary Services: SRP supports ancillary services being outside of the market optimization on day 1; however, SRP would be open to discussions on adding the co-optimization of ancillary services at a later time. SRP also requests clarification on how infeasible market solutions might be resolved if the market is not able to deploy scheduled regulation up or down. Will a different reserve be introduced by the market to be deployed on a real-time basis? How would this differ from regulation?
- Load and Renewable Energy Forecasts: SRP appreciates SPP providing load and renewable energy resource forecasts but requests that SPP also consider allowing participants to provide their own forecast if it is proven to be statistically more accurate than the forecast provided by SPP.
- Day Ahead Market Optimization Horizon: SRP supports the SPP Marketing Monitoring Unit's (MMU) recommendation to consider an extra day in the optimization process to commit long lead time resources. This would also help align the gas day with the electric day.
- Congestion Rent: SRP agrees with APS and requests additional detail be provided for congestion rents, including examples.
- Convergence bidding: SRP supports delaying convergence bidding for a minimum of one year to allow the market to mature and stabilize.
- Types of Market Schedules: SRP request clarification of how schedules are determined for Purchasing-selling entities (PSEs). If determined through e-tags, SRP is concerned the use of e-tags may not complete prior to market processes. Additionally, as stated on page 68 in the *Day-Ahead Clearing Process* section, transmission service reservations (TSRs) are not approved until the day-ahead market completes, potentially resulting in curtailment or denial of e-tags.

- Dispatchable Interchange Schedules: SRP requests clarification on how contracted spinning capacity factors into dispatchable interchange schedules if called on in the real-time market but only supported in the day-ahead market.
- Seams: SRP supports SPP's proposal to form a seams task force and appreciates SPP's recognition of the importance of this topic.
- Previous comments: SRP submitted comments encouraging the SPP to provide clarification and additional information where possible for the following topics:
    - Will outages be accounted for after the market participants have made offers and bids by the current 09:30 PPT deadline, and will the day-ahead market or the day-ahead RUC process capture the outage?
    - Dispatchable interchange schedules will be converted into a fixed interchange schedule for the day-ahead market. Will the left-over generation be released for use in the real-time market? Will the tags automatically be updated to the awarded amounts, or will this be a notification that will require additional changes to the e-tag?
    - SPP's optimizer will take all the generation and loads and balance from a day-ahead look and balance this out. Is a draft base schedule / gen plan submitted with this, or is SPP planning to have the optimizer complete the full balance? Will there be testing in advance to identify any shortages in scheduled needs allowing the BA to cure this prior to the optimization run?
    - How will generator redispatch be identified in the market award as being optimized? Page 56 under *Imports* states that the M+ system does not deliver external generation to a specific load inside of the footprint; rather, this will be handled by a redispatch using the sink to determine the location. Is there a specific plan for how these changes will be received by the BA?
    - The process to determine the settlement of an import is unclear to SRP from the *Imports* section on page 56. It is SRP's understanding that the border of M+ will be used to determine the Locational Marginal Price (LMP) for the import tag. SRP requests that SPP provide an example of this process moving through multiple BAs or expand the calculation shown in example on page 56.
    - SRP requests more information and the formula for settlement of in and out tags.
    - SRP requests additional explanation on the design goals, congestion rents determination for the M+ congestion rents and specific examples regarding the transmission service and congestion rents.
    - How will BAs forecast gas usage for awards that should appear around 13:00 PPT? It looks as if there are some initial outputs from the Multi-Day Forecast (MDFC); however, these are non-binding on the awards that could change.
    - SRP would like to see specific examples of how successful the MDFC is with more extreme environments in the existing SPP footprint for both overall load forecast and variable generation forecasts. Specifically, can SPP include overall load and variable generation forecasts for the 2022/2023 timeframes for the Desert Southwest (DSW) entities for comparison against both CAISO and internal forecasts?
- GHG Accounting
    - SRP supports the zonal approach for greenhouse gas market design in M+.

- SRP encourages SPP to establish working groups to identify data requirements for tracking and reporting purposes. To the extent that SPP can facilitate the streamlining for multiple GHG zones will enhance the M+ program.
- SRP encourages SPP to continue stakeholder engagement surrounding supply redesign concerns and providing simulated model examples of the two-pass solution so that stakeholders can understand the impacts.

TRANSMISSION comments:

- As noted in previous comments, SRP requests the following clarifications:
  - Day-Ahead transmission: the proposed methodology includes a freeze period for Open Access Transmission Tariff (OATT) transmission sales to begin at 0X00 MPT to facilitate market use of available transmission. Will this be on a firm or non-firm basis?
  - Real-Time transmission: SRP would like clarification on the timeframe for which the transmission is procured for the real-time market.
- SRP continues to request clarification and additional information on the following topics:
  - Accurate TSRs: SRP requests clarification on what the Transmission Service Provider (TSP) will provide to M+ for accurate TSRs and when the information will be needed. Is this planned just at the start of the initial optimization run, or will this be throughout the DA and into real time on a more constant basis via Inter Control Center Communications Protocol (ICCP)?
  - TSRs between M+ BAs: SPP references documenting TSRs between M+ BAs on the TSP Open Access Same Time Information System (OASIS) with a special sub-type of service similar to Joint Dispatch Transmission Service used in the Western Energy Imbalance Service (WEIS) market. SRP is unfamiliar with the WEIS processes, therefore requests SPP provide additional clarification on these processes.
  - Pancaked Transmission: SPP indicates that transactions wheeling out of the M+ footprint or across the M+ footprint would continue to pay pancaked transmission rates based on the approved rates of the TSPs whose systems make up the wheels but transmission would be non-pancaked between M+ BAs for intra-market schedules. SRP understands that pancaking would not happen between M+ BAs; however, pancaking would happen if the Point of Receipt/Point of Delivery (POR/POD) is external to the M+ footprint. Please clarify if pancaking would occur if either the POR or the POD is internal to the footprint. SRP also requests that SPP clarify if it will monitor and settle all wheel throughs. SRP requests a walk-through of this process during a future workshop.
  - Use of Transmission Service for Market Dispatch: SPP references that network customers designate generating units to serve network load under its network transmission service. If M+ delivers lower cost energy to the network load, the generators are considered non-designated resources. Please clarify if M+ participants would be expected to designate resources for participating in M+. Is the expectation that if this load is served by alternate lower cost generation, the network BA would settle for the lower cost and put the remaining capacity into the RT Market?

- Unused Transmission Capacity: SRP recommends SPP clarify any restrictions on time for sales of unused transmission capacity after the optimizer generates a solution. Will M+ be utilizing OASIS to track these changes, or is there an expectation that the BA will submit the updates to SPP?
    - Flow-Based Market Operations and Physical Deliverability: The Draft Service Offering states that curtailment of transmission service will continue to be the responsibility of the TSP, BA, and Reliability Coordinator. Will curtailment information be shared with the Real-Time Market Operator (RTMO) through M+? SRP requests additional information on the proposed process for sharing curtailment information.
    - Flexibility Reserves: SRP appreciates SPP's acknowledgment that the design of flexibility products will require additional analysis and stakeholder input.
    - Operating Reserves: SRP requests clarification of the RTMO's role in ensuring the centralized unit dispatch and BA actions are complementary and do not contribute to unforeseen risks to reliability
    - Optimizer: SRP encourages SPP to share current plans for how the optimizer will deal with times when the supply and demand cannot be balanced. Will there be additional notifications, or is there an expectation that this will be identified in the earlier advisory runs?
    - Day-Ahead Clearing Process: SRP recommends TSR requests, described on page 68, submitted prior to market run be approved, and then allow the market process to utilize what is left. SRP is concerned that day-ahead TSRs will not be approved after day-ahead trading and prior to the market run. TSPs that hold confirmation on next day transmission requests until the day-ahead market completes to avoid overselling could potentially leave day-ahead schedules and deals "in limbo" until after the market clears at the end of the day, which could cause tags to be late or transactions to be unable to flow as agreed upon in the morning trading session.
- Market Transmission Service (MTS):
    - SRP requests SPP provide clarification on how Market Transmission Service (MTS) aligns with the NERC priorities listed below.

Home > Program Areas & Departments > Reliability Risk Management > Transmission Loading Relief (TLR) Procedure > Transmission Loading Relief (TLR) Procedure > Transmission Service Reservation Priorities

Transmission Service Reservation Priorities

Transmission Service Reservation Priorities		
Priority	Acronym	Name
0	NX	Next-hour Market Service
1	NS	Service over secondary receipt and delivery points
2	NH	Hourly Service
3	ND	Daily Service
4	NW	Weekly Service
5	NM	Monthly Service
6	NN	Network Integration Transmission Service from sources not designated as network resources
7	F	Firm Point-to-Point Transmission
	FN	Network Integration Transmission Service from Designated Resources

    - SRP requests SPP clarify what Transmission Service Reservation Priority the day-ahead market will utilize. The *Real-Time Transmission* section on page 67

suggests M+ will utilize “0-NX” transmission, however, does not specify which TSR the day-ahead market will utilize.
    - SRP recommends SPP assign a new or existing Transmission Service Reservation Priority to ensure compliance with the North American Energy Standards Board (NAESB) preemption/competition process.
    - SRP requests SPP clarify the impacts to MTS with the transition of Arizona utilities from MOD-029 to MOD-030 and its overall impacts to transmission capacity and the projected timing to recalculate the revenue recovery amount (RRA). Does SPP foresee this happening on an annual basis or anytime additional capacity is considered used and useful?
- <u>Transmission Availability</u>: SRP requests SPP clarify when transmission availability for market use will be determined during the day-ahead process and when a security-constrained economic dispatch solution (SCED) will be derived based on day-ahead bids and offers while respecting OATT rights committed before the day-ahead.
- <u>Day-Ahead Market Transmission</u>:
    - SRP encourages SPP to further define the timing for transmission made available for the day-ahead market by the TSP. As noted on page 67, all transmission made available for the day-ahead market from the TSP should remain available until after the day-market completion to avoid over selling transmission. Clearly defining timelines will be important. SRP requests SPP clarify if M+ position be established:
        - Prior to trading the bilateral Market/ M+,
        - After trading the bilateral market but prior to bidding into M+,
        - After trading the bilateral market and after bidding into M+, or
        - At another time
    - SRP requests SPP clarify when it will communicate the results of any price sensitive dispatchable schedules to participants with the results of the day-ahead market outlined on page 67.
- <u>Hold Confirmation Next Day Transmission</u>: SRP requires clarification on how TSPs will hold confirmation on next day transmission requests until the day-ahead market completes to avoid over selling, as referenced on page 68. SRP is concerned this may not be feasible per the NAESB rules referenced in Table 4-2. For example, if a Transmission Customer on 10/17/22 at 11:15 requests 50 MW SRP NF Daily PTP Transmission from PaloVerde500-WestWing230 for 10/18/22, the SRP Transmission Provider function has 30 minutes to evaluate the request. The SRP TSP function cannot simply “hold confirmation on next day transmission requests.”

TABLE 4-2
PTP REQUEST TIMING REQUIREMENTS

TS_CLASS	SERVICE_INCREMENT	Time QUEUED Prior to Start	Transmission Provider Evaluation Time Limit[1]	Transmission Customer Confirmation Time Limit[2,10] after ACCEPTED or COUNTEROFFER[3]	Transmission Customer Confirmation Time Limit[2,8,9,10] after CR_ACCEPTED or CR_COUNTEROFFER	Transmission Provider Counter Time Limit after REBID[4,10]
NON FIRM	HOURLY	<1 hour	Best effort	5 minutes	N/A	5 minutes
NON FIRM	HOURLY	>1 hour	30 minutes	5 minutes	N/A	5 minutes
NON FIRM	HOURLY	>8 hours	30 minutes	30 minutes	N/A	10 minutes
NON FIRM	DAILY	N/A	30 minutes	2 hours	N/A	10 minutes
NON FIRM	WEEKLY	N/A	4 hours	24 hours	N/A	4 hours
NON FIRM	MONTHLY	N/A	2 days[5]	24 hours	24 hours	4 hours
FIRM	DAILY	<24 hours	Best effort	2 hours	N/A	30 minutes
FIRM	DAILY	N/A	30 days[6]	24 hours	N/A	4 hours
FIRM	WEEKLY	N/A	30 days[6]	48 hours	N/A	4 hours
FIRM	MONTHLY	N/A	30 days[6]	4 days	4 days	4 hours
FIRM	YEARLY	60 days[7]	30 days	15 days	15 days	4 hours

MARKET SETTLEMENTS comments:

- As the market settlements design advances, SRP encourages an approach that will promote high levels of transparency and minimize complexity.
- SRP remains concerned with the proposal for settlement meter data to be due four days after the operating day (OD+4). This could be problematic, especially on Mondays, if meter data require corrections. SRP encourages SPP to consider a period longer than four days.
- SRP agrees with the settlements comments made by APS. Like APS, SRP requests that SPP provide more detail on the following topics:
    - Over collection of losses
    - Out-of-merit energy
    - Miscellaneous adjustments
    - Applicable distribution charges
    - Distribution methods for “allocation” related settlement categories
- SRP suggests that SPP establish a settlements task force during Phase One.

MARKET MONITORING comments:

- SRP requests clarification of a statement on page 77 of the Draft Service Offering in the last paragraph under *Mitigation*. The paragraph explains that mitigation design should reflect the conditions of each market and that the MMU recommended a mitigation design to limit the exercise of system wide market power in the WEIS. The paragraph goes on to state, “Given the makeup of the market, the MMU does not see a need for a comparable mechanism." It is unclear to SRP if this statement is referring to M+ or another SPP market.

- The Draft Service Offering stated that the SPP MMU performed a market power study in advance of the approval and implementation of the WEIS market to determine whether and to what extent structural market power existed. SRP supports SPP taking a similar approach for M+ and encourages a market power study before recommending monitoring and mitigation design.

STAKEHOLDER RELATIONS comments:

- SRP agrees that training is a valuable service of the market operator and supports SPP's proposed training offerings.

IMPLEMENTATION comments:

- SRP has participated in several conversations with other entities on the challenges of energy-limited resources, specifically natural gas, hydro generation, and storage. SRP recommends the creation of a task force or working group at the start of Phase One to develop a solution to address the challenges of these limited resources in a day-ahead market.
- Timeline and Budget
    - SRP requests clarification of the $500,000 per month rate to support responses, technical analysis, and research necessary to gain FERC approval following the initial 21-month schedule for Phase One. SRP requests that SPP explain in the Final Service Offering how it plans to allocate this fee to potential participants.
    - SRP requests that SPP describe the incentives for potential participants to fund Phase One. It is unclear from the Draft Service Offering what advantages participants that fund Phase One will have that will not be available to non-funding participants that join M+ after implementation is complete.

CONCLUSION comments:

SRP looks forward to discussing these topics with SPP and continuing to explore solutions. SRP encourages SPP to address stakeholder comments to the extent possible in the upcoming development webinars and final service offering, prior to the Phase One – Tariff Development.

Western Freedom Comments on the Proposal for Southwest Power Pool's Western Day-Ahead Markets and Related Services

Western Freedom is pleased to submit these comments on the Southwest Power Pool's draft service offering for Markets+.

About Western Freedom

Western Freedom (WF) is a non-profit entity with the mission of enabling the delivery of low-cost electricity and energy freedom to the West through an efficient and integrated grid system. WF is focused on developing and executing a campaign to support the development of a western regional transmission organization ("RTO") on behalf of a coalition of large energy customers across the region. WF is focused on eleven western states including Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. WF is not taking a position about which entity should run region-wide markets over what footprint.

General Comments

WF appreciates SPP's success in developing markets to provide much more economic and reliable power in its service area. We observe that SPP's integration of low-cost carbon-free energy is now many times higher than SPP itself predicted it could have handled and is well above what could be incorporated had the 16 balancing authorities not consolidated.

WF has engaged in SPP's stakeholder process for western market development since March 2022 and we appreciate the opportunity to provide feedback on the draft service offering with the goal that SPP's market design choices will best serve customer interests. Western Freedom is not taking a position about which entity should run region-wide markets over what footprint.

The value of organized power markets in the west, especially a full RTO with a large, geographic footprint, was validated in the State-Led Markets Study.[1] A September 2022 study by the Brattle Group looking at a case of more limited market expansion also showed significant annual savings.[2] These studies demonstrate that even limited organized markets in the west would save customers millions of dollars per year, with a full west-wide RTO achieving combined gross benefits of nearly $2 billion per year.

Western Freedom strongly believes that market proposals should aim to unlock these savings for customers as soon as possible and should be designed to facilitate progress toward full RTO services.

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[1] See: https://static1.squarespace.com/static/59b97b188fd4d2645224448b/t/6148a012aa210300cbc4b863/1632149526416/Final+Roadmap+-+Technical+Report+210730.pdf

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

WF offers the following specific comments on elements of the Markets+ Draft Service Offering

3.2 Markets+ Independent Panel (MIP)
WF supports the seat for large energy and industrial customers on the MIP. This representation is critical to provide a voice to those who are most dependent on reliable and affordable service.

3.3 Committees Advising the Markets+ Independent Panel
WF supports the establishment of a senior committee of stakeholders to review Markets+ protocols and appoint relevant committees and single-issue task forces.

3.2.2.1 Markets+ State Committee (MSC)
WF strongly endorses the role and guidance of the states in the operation of the market including their vital input on market design and market efficiency. We also recognize that the MSC's authority can increase as additional functions are added to Markets+ scopes, such as weighing in on transmission and cost allocation policies in a manner similar to the SPP Regional State Entity. Western regulators developed Multi-State Electric Organization Principles which emphasize the need for state regulators to be involved in decision-making.

3.2.3.21 MIP Nominating Committee
WF is encouraged by the diversity of the 11 industry sectors that comprises the Nominating Committee. WF further encourages the development of a process whereby new sectors can be considered.

3.4 Other Committees and Stakeholder Groups
WF supports the Markets+ proposal to lower barriers for stakeholder committee participation and encourages that barriers remain low for participants including states, advocates, power marketers, and independent power producers. Discussion and vetting of issues in an orderly manner is central to regional development. WF has specific concerns that participation and voting in committees, task forces, and similar forums may be narrow and subject to appointment. This is the case in other organized market contexts which WF seeks to avoid. Independent generation participants including IPPs and non-transmission-owning utilities need to be accorded full voting rights, as do unaffiliated and independent transmission owners and large wholesale load interests. All require a seat at the table and the ability to participate in decision-making.

4.0 Governance Review
WF appreciates that SPP is building in a governance review three years after the Markets+ market launch.

Market Design
Energy and Reserve Markets
WF recognizes that energy market features proposed by Markets+ are modeled after best practices in other regions.

Congestion Rent Allocation

WF is encouraged by the Markets+ proposal to enable congestion rent to be allocated to existing and future Point-to-Point and Network Service transmission holders in lieu of the allocation of Financial Transmission Rights (FTRs). The Markets+ proposal will enable customers to schedule transactions in a manner comparable to existing rights.

Markets+ Market Design Key Features

WF is concerned that the Option Two proposal for multi-stage resource commitment in the day ahead market will lead to increased out-of-merit dispatch and cause higher uplift costs to customers, impairing price formation. Increased reliance on the RUC process in ERCOT demonstrates that this is a real risk. While no day-ahead market design will fully prevent uplift payments, WF is not convinced that the proposed change is an improvement over the voluntary financial market.

Reliability Unit Commitment

WF encourages Markets+ operators to evaluate the frequency of post-market close reliability commitments and off-cost payments to ensure that there is not overcommitment through the RUC process.

Real-Time Balancing Market

WF agrees that the appropriate interval for the real-time market should be 5-minutes

Resource Participation Models

WF supports a robust demand response program that will incentivize customers to make investments that benefit the system at large.

Price Formation

WF supports simultaneous co-optimization of energy and ancillary services in organized markets. It is an important advancement achieved in other select regions and strongly supports the efficiency in regulating price formation and the cost of operating reserves.

Centralized Unit Commitment

In WF's view, Markets+ will need to transition to a single balancing area following the market launch, particularly for subregions of the footprint that are contiguous. This will afford greater control and efficiency in operating the market and optimizing price formation. WF's customer coalition is strongly supportive of commitments toward planned balancing authority consolidation.

Physical Sufficiency in Markets+

Generation adequacy in the Markets+ footprint is essential. WF freedom encourages alignment with WRAP and physical capacity certainty in the day-ahead market timeframe.

Coordination with Resource Adequacy Programs

Additional work to coordinate between Markets+ and resource adequacy programs makes sense and WF is interested in seeing details.

Greenhouse Gas Pricing and Dispatch
WF would like to see additional detail on how the pricing scheme will ensure that GHG emissions goals are met in each jurisdiction with GHG regulations.

Markets+ Compatibility with Existing Constructs
Markets+ should honor and enforce existing contracts between buyers and sellers, and not interfere with the satisfaction of legacy transactions.

Greenhouse Gas Tracking and Reporting
WF requests additional details about the stakeholder engagement on Greenhouse Gas Tracking and Reporting and what standards and transparency Markets+ will offer to customers.

Transmission
WF acknowledges that transmission service procurement and administration will continue with the load balancing areas once Market+ commences operation. However, in time, the creation of a single tariff with license plate rates would be a way to end rate pancaking and further enable third-party wheeling across the Markets+ footprint. Such an enhancement post-market implementation would encourage increased participation by all customer segments including utility and Independent Power Producer (IPP) participants. If IPPs can sell directly into the market, customers will benefit from more new, low-cost generation.

Market Monitoring
WF supports the Market Monitoring Unit's engagement in the design and implementation of SPP markets, in addition to reviewing market operations. WF is encouraged by the breadth of market monitoring proposed in the Draft Service Offering. WF supports the Market Monitor having the ability to refer issues to FERC and ensure the market operates appropriately and in a competitive manner on behalf of customers.

Thank you for the opportunity to provide comments on this draft service offering.

Signed,

Larry Holdren
Executive Director
Western Freedom

October 28, 2022

Western Interstate Energy Board

Alberta
Arizona
British Columbia
California
Colorado
Idaho
Montana
Nevada
New Mexico
Oregon
Utah
Washington
Wyoming

David Bobzien
Chair

Maury Galbraith
Executive Director

October 25, 2022

Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223-4936

RE: Remarks of Western Interstate Energy Board

Dear Southwest Power Pool,

Since the formation of Markets+, the SPP Governance Design team has been working with the Western Interstate Energy Board (WIEB) to engage Western state regulators and energy office officials on the governance and program designs. Over the last few months, Western state representatives have participated in webinars with the Governance Design team and submitted comments and remarks on the various straw proposals in the hope of creating a robust market for the West. The West is evaluating multiple market options, all with the potential to bring significant benefits to utilities and their customers, and we thank SPP for continuing to work with the Western states and incorporating their recommendations into the draft service offering, ensuring that these benefits can be realized.

We acknowledge that the draft service offering has incorporated many of the state recommendations, such as clearly outlining the authority of the Markets+ Independent Panel and the process for appealing MIP decisions to the SPP Board of Directors. We appreciate that the Markets+ States Committee will have an independent staff that is fully funded by SPP to support the MSC's advisory role on the on-going design and governance of Markets+. As an agency of the Western states, WIEB thanks SPP for including these critical recommendations in its service offering, and we look forward to continued engagement with SPP on Markets+.

Sincerely,

Maury Galbraith
Executive Director

Gia Anguiano
Government Relations Specialist

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Thursday, October 27, 2022

Western Power Pool Comments on SPP's Proposal for Western Day-Ahead Market and Related Services (Markets+) Coordination with Resource Adequacy Programs

The Western Power Pool (WPP) submits the following comments on the section of the SPP proposal entitled, "Coordination with Resource Adequacy Programs". WPP appreciates SPP's care and attention to this important issue. WPP appreciates that SPP has identified the assessment of interoperability with the Western Resource Adequacy Program (WRAP) and other resource adequacy programs in its proposal, as well as a task focused on coordination with western groups and agencies to ensure coordination and interoperability between the market and other programs and services. WPP also appreciates SPP's dedications of staffing and resources to this issue, in particular the task force contemplated in SPP's proposal on this topic.

WPP recognizes that entities across the West are actively evaluating market expansion alternatives, including Markets+. WPP fully supports market expansion for the western grid and desires to be a partner in regional stakeholder discussions on these topics to help advance these efforts and to identify solutions that ensure WRAP can deliver its value proposition to its participants. WRAP's value proposition relies on its forward showing and operations programs working together to allow WRAP to deliver high-quality reliability and diversity benefits to its participants. An overlay of markets needs to be carefully thought through to identify whether any WRAP and markets interactions exist and if those interactions pose a risk to the WRAP value proposition.

Implementing a west-wide resource adequacy program like WRAP must be the priority consideration for the region. The efficiencies that markets bring are an essential component for western grid expansion, however, while markets serve to enhance economic efficiencies and reliability in the operational timeframe, they are not equivalent to the reliability and diversity benefits that can only be achieved through the advance planning, coordination, and compliance framework that WRAP can provide. In its proposal, SPP makes a similar comment, noting "Resource adequacy and capacity sufficiency occur over much longer planning horizons than the market processes contemplated for Markets+." As such, WPP fully endorses SPP's focus on the issue of interoperability of Markets+ with WRAP and emphasizes that durable reliability should be the priority consideration of stakeholders in the region.

Regional conversations on the topic of WRAP-markets interoperability are still early and high-level. In these nascent discussions, making WRAP work with markets appears to be technologically possible from a conceptual level, but more detail is needed to explore the additional layers of detail and complexity that must be examined in order to ensure that WRAP can deliver its value proposition to its participants that have selected a market expansion option.

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Thursday, October 27, 2022

To this end, WPP and participants in WRAP, working through the Resource Adequacy Participants Committee (RAPC) have recently finalized a set of WRAP-Markets Interoperability Principles to help guide regional discussions on WRAP-markets interoperability. These principles are as follows:

WRAP-Markets Interoperability Principles

The Western Resource Adequacy Program (WRAP) has always embraced an objective of compatibility with existing and future western organized market, including those being developed and operated by CAISO and SPP.

The WRAP will continue to support the development and evolution of these western organized markets and the ongoing ability for WRAP participants to participate in such markets, while ensuring that the reliability and economic benefits of WRAP are maintained or enhanced.

To achieve the interoperability of WRAP and western organized markets, western organized markets should:

1. *Be designed such that they do not interfere with or preclude participation in the WRAP.*
2. *Respect the governance framework and decision-making of the WRAP.*
3. *Preserve the diversity and investment cost savings derived from participation in the WRAP.*
4. *Preserve the supply priority and OATT transmission priority of WRAP forward showing supply to meet WRAP obligations.*
5. *Preserve the delivery of diversity benefits (holdback and energy) in the operational timeframe from one WRAP participant to another, including from WRAP participants in one organized market to WRAP participants in another or no organized market.*
6. *Seek to collaborate with WRAP to ensure compatibility and to achieve potential operational efficiencies and reliability benefits for all WRAP Participants.*

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Thursday, October 27, 2022

These principles, endorsed by WPP and RAPC, should serve a guidepost in regional discussion on WRAP-markets interoperability. Ideally, market operators should be able to identify and articulate the elements and attributes of their respective day-ahead market design that address each principle.

In its proposal, SPP proposes that it will not create or establish its own comprehensive resource adequacy program but will require participants to comply with an existing program, such as the WRAP. WPP commends and fully supports the direction SPP is taking to address the resource adequacy foundation for its future market. WRAP's carefully constructed design is the product of over three years of collaborative work by 20+ participating entities and stakeholder contributors. The WRAP footprint based on current participation is broad and West-wide. It is supported by a thoughtful, balanced governance framework that is also the product of many months of regional negotiation with state regulators and myriad stakeholders. WRAP's value proposition potential increases with as broad a participation footprint as possible and for this reason, WPP believes that WRAP is the best resource adequacy program to support Markets+. In WPP's view, the only way for another program to be "equivalent" would be an exact reproduction of WRAP, which makes little sense from an administrative, governance or economic perspective and which could significantly threaten the ability of WRAP to deliver its value proposition. Therefore, as a requirement for Markets+, WPP cautions against allowing for compliance with alternative resource adequacy programs under any kind of an "equivalent requirements" comparison measure to WRAP. WRAP's ability to deliver reliability and diversity benefits to the footprint significantly depends on the carefully constructed framework of planning, compliance, and operational requirements that obligate WRAP participants to fulfil their commitments to the program and to fellow participants.

WPP thanks SPP for its thoughtful consideration of this matter and its partnership in reaching solutions that meet the needs of participants. WPP looks forward to supporting these discussions and to participating in the joint taskforce between Markets+ and resource adequacy programs.

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WPTF Comments on the SPP Markets+ "Draft Service Offering"

October 28, 2022

Introduction

The Western Power Trading Forum (WPTF) is a California nonprofit, public benefit corporation. It is a broad-based membership organization dedicated to enhancing competition in Western electric markets while maintaining the current, high level of system reliability. WPTF supports development of competitive markets throughout the West and of uniform rules to facilitate transactions among market participants. The membership of WPTF includes energy service providers, generators, power marketers, scheduling coordinators, financial institutions, energy consultants, and public utilities. WPTF's membership actively participates in electric power markets in the West and across the country. WPTF has actively participated in the stakeholder process that the Southwest Power Pool (SPP) has facilitated to develop the "Markets+" Draft Service Offering, including participating in working group meetings and providing comments on various elements of Markets+ through the stakeholder process

WPTF appreciates the opportunity to provide comments on Markets+ Draft Service Offering which was released on September 30th. As WPTF has previously stated, SPP should be commended for the work it has put into the design of Markets+ so far and for its efforts to work collaboratively with stakeholders on the specific design elements for this market. WPTF generally supports a number of the elements in the Market Design Working Draft, including direct settlement relationships between resources and SPP (the market operator), the high-level concept of seeking to align congestion revenue allocation with transmission service, and the exploration of different unit commitment structures. We also appreciate that SPP has addressed some of our previous comments. However, there remain several areas of the design that require additional detail and clarification or require modification, as discussed more in these comments. We look forward to further discussions and engagement as SPP works with potential market participants and stakeholders towards the development of the Final Service Offering and to the refinement of the design that will come in the next phase of market development.

Governance

SPP has worked with stakeholders to develop a governance solution which seeks to provide as much autonomy and independent oversight as possible to the proposed Markets+ Independent Panel (MIP) and to the Markets+ Participants Executive Committee (MPEC) while allowing the existing SPP Independent Board to retain its role overseeing the SPP organization as a whole.

The recent changes that have been made to the governance proposal help bolster a durable governance solution for Markets+. WPTF appreciates the current version of the MPEC voting structure proposal, which uses a sector-based approach. This approach to MPEC voting should represent a step forward in providing independent entities with a voice in Markets+ and with addressing concerns around providing a meaningful role for stakeholders, especially when coupled with the ability for nonprofits to seek a waiver of the annual fee for being a Markets+ Market Stakeholder. We also appreciate that, pursuant to recent changes to the governance proposal, the SPP Board member that sits on the MIP will ***not*** automatically be named Chair and that the MIP will be able to select its own Chair. This is a meaningful improvement that will provide more autonomy to the West.

WPTF suggests one minor modification to the governance proposal: that the relevant experience criteria for MIP members be expanded to allow for a broader set of experience to qualify, such as environmental/clean energy policy experience. Allowing a broader set of experience to qualify may help the MIP include more diverse perspectives and address issues that are particularly important in the West, such as GHG accounting.

While there is always room for improvement, at this time, WPTF generally supports the proposed governance structure for Markets+.

Market Design & Transmission

Market+ has the potential to be a unique market construct, one which will enable more coordinated day-ahead unit commitment and dispatch across the footprint while individual Balancing Authorities (BAs) retain their reliability responsibilities and Open Access Transmission Tariffs (OATTs) are retained. Given that this market will not function in the same manner as a typical Regional Transmission Organization (RTO), the unique approach proposed to combine day-ahead and real-time commitment and dispatch across multiple BAs and OATTs, requires careful consideration, coordination, and assessment of the potential impacts. While Markets+ will not be perfect on "day one" of operation (as no market before has been), this construct requires an attention to detail and thorough assessment of its potential impacts during the market design phase.

Some of these details and considerations will, necessarily, be taken up in subsequent phases of market design. WPTF's comments in this section point out areas where modifications/adjustments to the current design should be made and also highlight areas where additional discussion is required. Overall, ensuring that the rules for the market are reasonably consistent and offer fair and equitable transmission access will be critical. Many details around implications for transmission priority, congestion management and curtailment may not be fully understood until the next phase of market design. But, in the meantime, providing key modifications to Markets+, such as an "opt out" provision for transmission, and a development mechanism to allow exports from Markets+ to document association with a specific resource, are critical. We look forward with working with SPP, potential Markets+ market participants, and stakeholders as Markets+ design move into the subsequent phases and additional attention is aid to key issues that result from the overlap of a centralized unit commitment/dispatch overlayed on the existing OATT structure.

Markets+ Transmission Requirements: The Markets+ Market Design Should Include Acceptable Parameters for any Transmission Requirements that Transmission Service Providers may seek to apply to Resources Bidding into Markets+

WPTF understands that, because Markets+ is not a full transition to an RTO, it is intentionally being designed to help preserve the value of transmission rights [(and reduce impacts to transmission revenues received by Transmission Service Providers (TSPs)]. Part of the way the value of transmission rights will be preserved is through allocation of congestion rents to transmission rights holders. WPTF supports that goal and the proposed allocation of congestion rents under Markets+. But we also highlight the critical importance of the ultimate market design appropriately balancing the need to preserve the value of transmission rights with the goal of incenting resource participation and the essential objective of ensuring fair and open access to the market. In order to ensure open access to the market, WPTF urges the market design to address transmission requirements, both at the Market Operator level, and by participating TSPs/BAs.

At this time, it appears that the Markets+ design itself will ***not*** require transmission rights/transmission service reservations for all bids submitted or dispatch instructions provided by Markets+. Rather, in the Markets+ design, holding transmission rights will provide several incentives, but will not be required by the Market Operator in order to participate in the market. WPTF requests clarification from SPP that this interpretation is correct. Additionally, examples would help provide enhanced insights into any applicable tagging and transmission requirements that the Market Operator may be contemplating for Markets+. One example (or set of examples) that would be helpful to explore, is a situation where a third-party generator that has transmission rights for part (but not all) of its output and it wishes to bid its incremental, available output into Markets+.

Beyond any transmission requirements that may be imposed by the Market Operator, it remains unclear what types of transmission service requirements might be sought to be imposed by TSPs or BAs that participate in Markets+. Certain transmission requirements that could, theoretically, be imposed by transmission providers would severely limit the potential benefits offered by the market and may create an undue burden for third-party resources. WPTF urges SPP to clearly define what types of transmission requirements will be acceptable for TSPs/BAs to impose on resources under the Markets+ framework. Having these requirements outlined in the Market Operator tariff/market design will be critical to ensuring fair and open access to the market and to preventing undue discrimination against potential third-party participants. While, for many TSPs/BAs, FERC may ultimately review and approve any proposed transmission requirements to enable Markets+ participation, this is not the case for all potential Markets+ participants (as many are non-FERC jurisdictional). Thus, SPP as the Market Operator, should build safeguard into its market design which ensure fair and open access and reasonable consistency in transmission requirements across the entirety of the market footprint. WPTF urges SPP to develop a set of acceptable transmission requirements that TSPs would be permitted to implement for Markets+ that will enable fair and open access to all interested participants.

Clarification on the Unit Commitment Process and Implications for Market Transmission Service

Markets+ has the potential to be a unique market construct, one which will enable more coordinated day-ahead unit commitment and dispatch across the footprint while individual BAs retain their reliability responsibilities. In order to maximize the benefits of the market, it is imperative that BAs have confidence that they can depend on transfers from Markets+ to meet their commitment and energy needs across the day. In order to increase benefits of the market, it would also be helpful for Markets+ to enable realization of geographic diversity benefits and associated reduced reserve/ramping requirements across the footprint.

As SPP has acknowledged, since the individual BAAs in Markets+ will not consolidate, it is important for each to remain "*individually sufficient before and throughout the operating horizon*." SPP has also noted that the "*transmission capability made available for centralized unit commitment and dispatch will be a key input*" to Markets+ and one which could serve to constrain the centralized unit commitment of the market optimization between BAs. SPP has indicated that the next phase of market design will determine specific details of how this constraint will be modeled and implemented.

WPTF looks forward to these future discussions and additional details. In order to maximize the benefits of the market, it is imperative that BAs and market participants have confidence that they can depend on transfers from Markets+ to meet their commitment and energy needs across the day. It is only with this confidence that the market can achieve the benefits of broader unit commitment. Thus, how transmission capability is made available for centralized unit commitment and dispatch, along with what priority it takes, will be integral to the market's success. We note that, as presently proposed, it appears Market Transmission Service (MTS) would be the lowest priority transmission service and would only be available for re-dispatch in real-time. Thus, MTS does not appear to be a viable option for day-ahead unit commitment and dispatch between Markets+ BAs. If this understanding is correct, it may help to address some concerns about the potential for Markets+ transmission use to pre-empt or override OATT transmission service priority.[1] But it also may constrain the market from maximizing benefits. This balance and the implications of which transmission is available for unit commitment and dispatch will need to be carefully considered in the upcoming phase of market development. WPTF looks forward to continue to engage in those discussions.

WPTF Appreciates Some Clarifications on MTS, but Continues to Oppose Hourly Calculation of the MTS Rate and its Application to Generation

The Draft Service Offering provides additional details and clarification on MTS and the process for calculating the MTS rate. WPTF appreciates several of the clarifications and modifications that were made in response to our prior comments. However, we continue to have concerns with the calculation of the MTS rate on an hourly basis. And, most importantly, we note that allocation of these charges to load only (rather than load and generation) would result in a more efficient market solutions and, thus, should be pursued.

WPTF appreciates that, consistent with our prior comments, the Draft Service Offering clearly specifies that the MTS-Recovery Scaling Factor cannot exceed 100% and, thus, the MTS cannot be used to recover lost transmission revenues in excess of the defined Qualified Recovery Amount for MTS.

Additionally, SPP has clarified that the calculation of the MTS rate on an hourly basis will be based on the total amount of energy cleared in the *real-time* market and will apply to all generation and load in the Markets+ footprint. This should help address, to some extent, a concern WPTF raised in prior comments about the potential volatility of the MTS rate when calculated on an hourly basis. However, WPTF continues to have concerns around the volatility/uncertain nature of the charge when calculated on an hourly basis. WPTF recommends a more stable and predictable rate for MTS and, therefore, urges the market design in the Final Service Offering to move away from use of transactions within an hour for calculating the MTS rate. Averaging the MTS charge over the transactions that occur in a given week, month, or year would help provide more stability and predictability to market participants regarding the charges they will receive for MTS.

The Draft Service Offering currently proposes to recover the MTS costs from *both* generation and load cleared in the Markets+ real-time market. Allocation of these costs to supply-side resources (generation) will create inherent uncertainty for those resources in submitting their bids, especially given the hourly calculation of the rates which will, by definition, have some volatility. This additional uncertainty/risk placed on supply-side resources is likely to be

[1] While this construct for MTS may address some concerns around Markets+ transmission use pre-empting use of firm transmission rights in real-time, WPTF requests additional discussion on the implementation of congestion management and curtailment orders in a Markets+ environment that layers onto the existing structures in the West.

reflected in bids. When supply-side resources seek to reflect these unknown costs in their bids, that is likely to decrease the efficiency of Markets+. Ultimately, load will end up bearing the MRS costs, whether they are initially applied to load and generation, or only applied to load. Given that, WPTF supports a more straightforward and efficient allocation of MTS costs to load only.

Discussion and Examples on Congestion Management and Curtailment

SPP should facilitate additional discussion around congestion management and curtailment responsibilities and implications of Markets+. In particular, WPTF has concerns around the interactions and potential confusion around any curtailment that may be necessary in a Markets+ environment. Under Markets+, congestion management and curtailment would include many different functional entities, including the Reliability Coordinators, Transmission Operators, and the Market Operator – all of which may be responsible for congestion management and curtailment. The Market Operator will have new interactions with these entities and it will be critical to understand the division of responsibilities and ensure that each Reliability Coordinator and Transmission Operator are interpreting the overlay of Markets+ within their current framework in a consistent way and in line with the market design envisioned for Markets+. Without additional clarity around congestion management and curtailment practices, entities may fear a degradation in the value of their transmission rights within Markets+, which is contrary to a key goal that Markets+ potential participants have articulated. We look forward to further discussion around this and, as discussed below, also urge SPP to provide a mechanism for transmission rights holders within Markets+ to hold transmission rights out of the market optimization.

Markets+ Should be Enhanced to Include Provisions for Transmission Customers to Withdraw Transmission from the Market

WPTF appreciates the work the SPP has put into developing rules for transmission provision into Markets+. At present, Markets+ would allow non-participating TSPs that provide service across the Markets+ footprint to "withdraw" their transmission from Markets+ optimization. And SPP would utilize Service Flow Constraints to recognize and respect those non-participating transmission rights. Given the remaining uncertainty on transmission priorities, curtailments and the desire to retain the value of transmission rights in a Markets+ construct, WPTF urges SPP to modify the Markets+ design to also allow *transmission rights holders/Transmission Customers* an option to hold their rights out of the market optimization.

Consistent with our advocacy in other, similar market venues, WPTF strongly believes there needs to be a way for entities to hold transmission rights out of the market optimization. We understand SPP and stakeholders' desire to create a market design that includes as much transmission and resources as possible. However, the current design appears to be obtaining that goal by forcing all resources, transmission rights/contracts, and load within a BA to participate in Markets+ in some way shape or form. And the imposition of Market+ has the potential to reduce the ability of Transmission Customers to utilize their transmission rights in real-time, which could reduce the perceived value of those rights. Providing a mechanism for transmission (or, even, transmission/generation pairs) to be excluded from the market optimization of Markets+ will help entities that are pulled into Markets+, by the decision of their BAA, to manage their own risk exposure. It could also provide a clear mechanism for these resources/transmission pairs to continue to demonstrate a generation-to-load delivery relationship for a load outside of Markets+ (which does not appear to be contemplated in the Markets+ Draft Service Offering, as discussed more below).

Compatibility with Existing Structures: Market Participants should be able to Associate Exports from Markets+ with Specific Resources

Markets+ is intended to work with many of the existing Western structures, including clean energy regulations. Prior discussions around Markets+ included many conversations around "Base Schedules" which could be used, in part, to demonstrate a relationship of an export from the market to a specific generator. The Markets+ Draft Service Offering appears to have eliminated the use of the term "Base Schedules" but retains the idea of allowing a demonstration of some types of generation-to-load relationships through the use of e-Tags. The document states:

> M*arket participants may utilize e-tags to document a bilateral agreement to establish a generation-to-load relationship between contractual entities.*

However, it is unclear whether, and how, exports from Markets+ can utilize e-Tags in order to associate an export from the Markets+ footprint with a *specific resource*. On page 57 of the proposal, under "Exports", the document states that:

> *Consistent with other organized markets, the export tag results in delivery from the Markets+ generation fleet, not an individual generator or source.*

WPTF understands that this structure of non-resource specific exports on e-Tags is consistent with other organized markets. However, this framework is not sufficient to enable by renewable generation within the Markets+ footprint to comply with the requirements of Portfolio Content Category (PCC) 1 under the California RPS program. Market participants that deliver energy from Markets+ to California pursuant to the RPS will need to be able to associate the e-Tag for that delivery to a *specific renewable resource* in the Markets+ fleet. For PCC 2 imports, which do not require direct delivery of renewable energy, this association is made by including the renewable resource's RPS ID in the token field of the e-Tag. This same practice may be able to be used to associate individual renewable resources within the Markets+ generation fleet to an export tag, allowing matching of the resource's metered generation to that e-Tag after the fact.

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Thus, we recommend that SPP clarify the process for creation of e-Tags for exports from Markets+ and work with stakeholders to ensure that market participants have the ability to associate e-tags to specific resources, such that generators will have options for demonstrating compliance with the California RPS program.

Marginal Losses: SPP Should provide Examples of Loss Treatment within the Markets+ Framework

The Markets+ Draft Service Offering indicates that losses will be reflected as a cost in the LMP as the marginal loss component, which will be included in the market's unit commitment and dispatch. WPTF generally supports the use of marginal losses in Markets+. We seek clarification, however, on language in the Draft Service Offering related to the settlement of losses by the host Transmission Service Providers. Specifically, the draft service offering states:

> *Losses will settle under the host transmission service provider with any impacts of losses reduced from Markets+ settlements to avoid double settlement of losses.*

Some high-level examples of the settlement process that SPP envisions for losses would be beneficial for stakeholders and potential market participants to better understand the implications. Additionally, WPTF urges SPP to define reasonable parameters for loss settlements by TSPs to ensure consistency and equitable treatment across the footprint. For instance, SPP could define what parameters losses will be settle on (e.g., day-ahead schedules, real-time schedules, actual flows, or some combination thereof). Ensuing consistent application of loss settlement (even if different percentage allocation factors are used by different TSPs) will help promote efficiency, transparency, and consistency in the Markets+ footprint.

Additional Discussions and Examples on Interoperability with the Western Resource Adequacy Program (WRAP)

WPTF generally supports the proposed structure for ensuring physical sufficiency in Markets+. Given the likely implementation of the WRAP by many of the parties interested in Markets+ participation, aligning resource adequacy and must offer requirements with WRAP is an elegant solution. However, the details will be critical. It is imperative to ensure that the must offer obligations for Markets+ are not overly broad and that they enable Markets+ participants flexibility in meeting holdback requirements for other WRAP participants which are ***not*** also Markets+ participants. Further discussion on the "interoperability" of Markets+ and WRAP are necessary and WPTF looks forward to participating in those.

GHG Accounting and Treatment

Designing a solution to address the two GHG pricing programs (cap and trade) that regulate imported electricity is a significant challenge. WPTF appreciates SPP's efforts to date and looks forward to continuing to work with SPP as more details are added to the GHG design for

Markets+. Similar to comments offered on prior Markets+ documents, below we offer some high-level comments and questions on GHG design as SPP works to develop additional specifics.

As an initial matter, it is worth highlighting that the GHG solutions for Markets+ will need to support implementation of state GHG pricing programs and be consistent with those state regulations. We continue to encourage SPP to seek to engage with Washington Department of Ecology staff as the design continues to ensure the Markets+ construct consistent with Washington's program.

WPTF is hopeful that, based on prior presentations and discussions, SPP plans for Markets+ to include submission of a GHG adder that is separate from the energy bid, for resources ***both*** within the GHG zone and outside the GHG zone. As WPTF has previously indicated, we believe that having resources within the GHG zones submit separate GHG bid adders provides more transparency and more accurate price formation. And we are encouraged that Markets+ appears to be moving towards adopting this approach. Nevertheless, we continue to encourage further discussion and exploration on this topic, along with other GHG issues.

WPTF also reiterates prior comments that the market's approach for GHG accounting will need to be defined within each state's GHG regulations and reflected in the market tariff. While we fully support SPP's continued development of the market design, finalization of the GHG design requires the adoption of rules by the appropriate state regulator on the conditions under which resources are eligible for resource-specific attribution, as well as a determination by that regulator of the compliance entity or entities for emissions associated with unspecified transfers. On the conditions for resource specific attribution, WPTF recommends that resources that have an energy contract with an LSE in a GHG areas also be eligible for resource specific attribution. This attribution could be implemented via a bid flag in the market construct. The eligibility of that resource for resource-specific attribution could be verified, after-the-fact, by the GHG regulators (assuming that the regulators adopt this condition in their regulations). Additionally, the market design should provide flexibility to generators to control when and what quantity of MW may be attributed to a GHG Zone so that they can meet their contractual requirements to LSEs, only some of which may be within a GHG Zone. Further, neither Washington nor California currently require transmission for resource-specific attribution for imports via an organized electricity market. WPTF would support a market design that allows resources that come to the market with transmission to be eligible to be resource-specific attribution, but we would oppose this a condition.

We look forward to additional discussion on the approaches that SPP is considering to address the "MW-Redesignation" concerns (which has also been called "Secondary Dispatch" in other forums). WPTF requests two modifications to the GHG Baseline approach in the optimization solution. First, we would argue that intent of the GHG Baseline is to approximate what and how resources would be dispatched to serve *native* load – not to approximate dispatch of resources in the entire non-GHG footprint. We therefore recommend that the GHG Baseline run should be conducted on a BAA-by-BAA basis (rather than the full non-GHG zone footprint), without allowing transfers between BAAs. This would enable clean generation that is not needed for native load to be attributed to a GHG Zone. Second, we urge SPP to limit the MW that can be attributed to a GHG Zone to the difference between that resource's GHG Baseline dispatch and its *actual* dispatch. We are aware of the concern that this latter change would create non-linearities in the market optimization, but believe that these can be resolved within the day-ahead market timeframe.

Lastly, we would also welcome additional discussion of the appropriate GHG emission rate for unspecified transfers. WPTF believes that the rate used should as closely as possible reflect the GHG emission rate of the marginal emitting resource within the market footprint.

Settlements

WPTF does not offer comments on the specifics of Markets+ settlements at this time. But we express our support for the direct settlement relationship between the Market Operator and customers that is proposed within Markets+. Under Markets+, transmission rights holders would directly settle congestion rents with SPP and generators would also directly settle with SPP. This direct settlement relationship increases transparency in the market and promotes a more consistent market construct than might exist with a less direct settlement relationship. Retaining that direct settlement relationship for transmission rights holders is also important to furthering the goal of retaining the value of transmission rights.

Market Monitoring

WPTF appreciates the details SPP has provided on its Market Monitoring Unit (MMU), which would presumably provide market monitoring services for Markets+. Market monitoring for Markets+ will require a special set of skills and a market monitor that can understand the interaction of the market functionality and the OATT structure. To the extent SPP's MMU provides market monitoring for Markets+, SPP should enhance the MMU by adding staff with prior expertise on Western bilateral markets and OATT structures and also, ideally, with the dynamics associated with energy-limited hydro resources.

WPTF has previously highlighted its support for a conduct & behavior approach to mitigation, in line with the general structure used by SPP's MMU. And we continue to support such an approach.

Additionally, we highlight that, for any market monitor, it is important that the market monitor focus on getting prices "right", not simply keeping them low. Part of achieving that goal require evaluating the actions of the Market Operator itself and we support a market monitoring approach that includes a strong focus not only on behavior of market participants but also the actions of the Market Operator.

Conclusion

WPTF appreciates the efforts SPP has undertaken on Markets+ so far and applauds SPP for the completion of the Draft Service Offering. However, there remain a number of unknowns that are critical to understanding the implications of Markets+. Additionally, as recommended in these comments, several modifications and enhancements are necessary. In particular, SPP should ensure that the Markets+ design provides crucial guardrails to ensure that implementation by TSPs/BAs is fair and equitable and promotes reasonable consistency across the market footprint. We look forward to continuing to work with SPP and other stakeholders as the Markets+ Final Service Offering is developed nd the effort moves into the next phase of market design.