

MARKETS



A PROPOSAL FOR SOUTHWEST POWER POOL'S WESTERN DAY-AHEAD MARKET AND RELATED SERVICES

*Part of SPP's Western Energy Services
family of products*



1 CONTENTS

1.0 INTRODUCTION: SPP AND ENERGY MARKETS	1
2.0 GOVERNANCE.....	5
3.0 MARKET DESIGN	22
5.0 TRANSMISSION	72
6.0 MARKET SETTLEMENTS	78
7.0 MARKET MONITORING	85
8.0 STAKEHOLDER RELATIONS	95
9.0 IMPLEMENTATION	96
10.0 CONCLUSION	100

Utilities have the daunting task of ensuring electric reliability and affordability for their customers. Southwest Power Pool (SPP) has proven that centralized, regional electricity markets make this task easier and more successful. We have years of experience and a customer-centric approach to market development. We provide more than just market development and administration services. We provide peace of mind.

SPP is pleased to present this proposal for Markets+, a bundle of proposed services that would centralize day-ahead and real-time unit commitment and dispatch, provide hurdle-free transmission service across its footprint and pave the way for the reliable integration of a rapidly growing fleet of renewable generation. We have made an earnest attempt to accurately estimate and clearly state the anticipated costs and obligations of designing, implementing and administering Markets+. We've based the market's design on both our own experience and the expressed wishes of you, our customer.

We look forward to continuing to work with you in developing a mutually beneficial relationship that will bring financial benefits and enhance electric reliability for your customers for years to come.

1.0 INTRODUCTION: SPP AND ENERGY MARKETS

1.1 A LEGACY OF TRUSTWORTHINESS

SPP has coordinated the reliability of the bulk electric grid for more than 80 years. We were founded in 1941, incorporated in 1994, approved by the Federal Energy Regulatory Commission (FERC) as a regional transmission organization (RTO) in 2004 and have grown and matured steadily throughout our history, constantly expanding our service offerings and territory to provide greater value to a continually growing and diverse group of customers.

Even as our services, responsibilities and staff size have grown, particularly in the last two decades, our values and commitment to serving customers have remained the same. We believe in doing the right thing for the right reason in the right way, and we've managed to stay true to those values even as we expanded our RTO footprint, extended our contract services and welcomed our first members in the Western Interconnection.

Our annual stakeholder satisfaction surveys regularly return superbly favorable results among our stakeholders, and our employee engagement surveys consistently show phenomenal levels of satisfaction, motivation and effectiveness among our highly qualified, dedicated and professional staff of more than 600 employees. All of this is proof: Our strategy is built to last.

1.2 OUR VALUE PROPOSITION: EXPERIENCE AND CUSTOMER SERVICE SET SPP APART

Our value depends on the complimentary principles of maintaining independence through diversity and a commitment to being stakeholder-driven. We are facilitators, helping our stakeholders work together to responsibly and economically keep the lights on today and in the future. We don't tell our stakeholders what to do. We facilitate dialogue among them, ensuring every voice is heard regardless of size.

SPP's approach to business is creating and maintaining a strong, unique culture in which our staff and stakeholders collaborate to be as effective and efficient as possible.

We share your values. We understand equally the challenges of managing transmission in rural areas and the importance of maintaining reliability in large population centers. The SPP RTO serves seven of the one hundred largest cities in the U.S. and has a keen understanding of rural America, too: after all, it's where we call home and is the area we have primarily served for the past 80 years.

We hire career employees and invest in them as people first and employees second. We give back to our community. We value transparency in our actions and communications, flexibility in our approach to customer service and response to industry trends and integrity and trust in everything we do. We consider ourselves partners with our stakeholders and stewards of their valuable resources.

We are proud that SPP today – having grown from 11 members in 1941 to 115 in 2022, spanning all or parts of 17 states and soon to provide service to even more in the west – still reflects our early principles of collaboration with an unwavering commitment to remain customer-focused.

SPP has a proven record of creating value for the companies we serve, who are as diverse as the services we offer. Our customers include investor-owned utilities, rural electric cooperatives, municipalities, public power, large retail customers, alternative power and state and federal agencies. In fact, we are the only RTO to count among its members a federal agency: Western Area Power Administration, Upper Great Plains Region.

The relationships we've forged and maintained not only serve as a testament to the integrity and strength of our business model but also as a foundation on which to build the next step in SPP's evolution.

1.3 SPP'S HISTORY OF SUCCESSFUL MARKET DEVELOPMENT

SPP launched its first energy imbalance services (EIS) market in 2007. With it, we set a precedent for huge returns on market-development investments. The EIS market's total implementation costs were approximately \$33 million, and in its first year alone it paid back its participants threefold, providing \$103 million in benefits.

Our 2007 EIS market was a real-time balancing market that dispatched participating generating resources to meet load every five minutes. Our members and market participants quickly saw additional reliability and economic opportunity in consolidating our 16 balancing-authority areas and expanding our market to perform day-ahead unit commitment. We began designing and implementing what would become our Integrated Marketplace.

In 2014, we launched the Integrated Marketplace on time and under budget with the highest degree of quality, something no other RTO in the world has accomplished. In its first year of operation, our expanded market delivered \$380 million in net savings to our members and their customers, paying for itself in just four months.

The Western Energy Imbalance (WEIS) market launched Feb. 1, 2021. The real-time balancing market is part of SPP's contract-based portfolio of Western Energy Services it provides customers in the Western Interconnection. The WEIS market helps keep wholesale electricity costs low, increases price transparency and mitigates congestion on the transmission system for market participants. Throughout its first year of operation, it has performed well and to the expectations of its participants, enhancing both reliability and economics and paving the way toward even greater value as it grows in size and leads to the development of Markets+.

SPP-administered markets save money and enhance reliability. In testimony to the House Subcommittee on Energy and Mineral Resources, then Western Area Power Administration Administrator and CEO Mark Gabriel said of his organization's participation in SPP's markets, "Our participation in energy and transmission market initiatives has delivered greater benefits than we anticipated ... In addition to experiencing financial and operational benefits exceeding our conservative assumptions, above-average water conditions resulted in surplus generation sales into Southwest Power Pool (SPP) that accrued more than \$48 million of additional net market revenue. These surplus sales help put downward pressure on firm power rates."

We have a long and successful history of providing contract services to nonmembers of the SPP RTO. We've provided tariff administration, reliability coordination, reserve sharing and planning authority services to dozens of entities in the Eastern and Western Interconnections.

It's on this foundation of success that we propose to build Markets+ and bring time-tested benefits to customers in the Western Interconnection.

1.4 THE SPP ADVANTAGE

SPP has worked for several years with utilities in the west to understand their needs and design solutions to ensure the highest levels of reliability while keeping rates as low as possible for customers. SPP understands that western utilities place high value on having a voice in helping shape the ever-changing energy landscape, and that the western utility landscape represents many diverse interests that must be balanced in every decision.

These objectives are at the heart of who SPP is and how we do what we do. Our customer-driven approach will ensure western customers get the products and services they need at affordable rates they help control. Our strength is in our ability to facilitate effective discussions of complex issues among diverse stakeholders while balancing impacts to the inseparable ideals of reliability and economics.

Our industry is undergoing transformational shifts in generation technologies, customer demands, environmental considerations and political expectations. SPP has more than 75 years of experience using a relationship-based business model to help customers meet their challenges in a way that fits the needs of their business, customers, stakeholders and regulators. We know you have a choice when considering your market options, and we believe after reviewing our proposal you'll agree our approach of providing a customer-driven energy imbalance market is the right choice for you and your customers.

WHY SPP?

- Strong customer involvement and transparent governance that balances the interests of all states and all participants
- Demonstrated customer-driven approach to decision-making
- Long-term cost certainty through customer-driven changes to service
- Efficient market operation and flow-based internal congestion management
- Future optionality for long-term market evolution
- Lower up-front and on-going costs for participating balancing authorities thanks to the market's direct interaction with embedded entities
- High utilization of legacy metering requirements
- No long-term commitments and low up-front and on-going costs for market administration

2.0 GOVERNANCE

2.1 DEFINITIONS

Affiliate: Affiliate relationships are relationships between Markets+ market participants that have one or more of the following attributes in common:

1. Are subsidiaries of the same company
2. One Markets+ market participant is a subsidiary of another Markets+ market participant
3. Have, through an agency agreement, turned over control of a majority of their generation facilities to another Markets+ participant
4. Have, through an agency agreement, turned over control of a majority of their transmission system to another Markets+ participant, except to the extent that the facilities are turned over to an independent transmission company recognized by FERC
5. Have an exclusive marketing alliance between Markets+ participants
6. Ownership by one Markets+ participant of 10% or greater of another Markets+ participant.

Federal Energy Regulatory Commission (FERC): The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of natural gas, oil and electricity. FERC is the regulatory agency that will oversee and approve Markets+.

Markets+ Independent Panel (MIP): A five-member panel that is independent from Markets+ participants and Markets+ stakeholders. The MIP is the highest level of authority for decisions related to the Markets+ market with the SPP board of directors providing independent oversight.

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.

Markets+ Market Stakeholder (MMS): Category of stakeholders who has executed a Markets+ stakeholder agreement, does not contribute generation and/or load to the Markets+ market and pays an annual fee of \$5,000. A MMS has voting rights at the MPEC, the MIP Selection Forum and is eligible for a voting seat, if appointed, on the MIP Nominating Committee, working groups and task forces. The annual fee may be waived for eligible entities that are nonprofit organizations under the Internal Revenue Code.

Markets+ Non-Voting Stakeholder (MNVS): General category of stakeholders who provide input at all stakeholder meetings that do not have voting rights on working groups and task forces and pay no annual fee.

Meeting of Markets+ Participants and Markets+ Stakeholders: A meeting of Markets+ market participants and Markets+ market stakeholders shall be held for the purpose of electing members of the MIP and conducting other business as necessary. The MPEC chair shall preside over these meetings.

SPP: Southwest Power Pool, Inc. or successor organization (SPP Bylaws).

Staff: The technical and administrative staff of SPP as hired by the officers to accomplish SPP's mission.

2.2 PARTICIPATION IN MARKETS+

2.2.1 QUALIFICATIONS AND PHASES

2.2.1.1 PHASE ONE: FUNDED INVESTIGATION

Entities that are supportive of SPP's development of a detailed Markets+ design, can commit a non-refundable amount to allow SPP to commit resources to designing the market functions, draft the governing documents and submit the proposal to FERC.

During phase one, to the extent practical, the governance structure described herein will be used to vote on the Markets+ tariff and protocols for recommendation to the SPP board to file at FERC for approval.

Because the Markets+ Independent Panel (MIP) is not expected to be established during phase one, a three-person subcommittee of the SPP board of directors will be established to perform the functions of the MIP described herein during phase one and until such time as the MIP is established.

To vote in phase one, entities must execute one of the following agreements:

1. **Markets+ Market Participant Phase One Funding Agreement:** Entities that have load and/or generation and want to vote in phase one must execute a Markets+ Market Participant Phase One Funding Agreement and pay SPP pursuant to its terms. These entities will be eligible to vote on the MPEC and have representatives eligible for appointment to working groups and task forces during phase one consistent with the governance structure described herein.
2. **Markets+ Market Stakeholder Phase One Participation Agreement:** Entities that do not have load or generation and want to vote in phase one must execute the Markets+

Market Stakeholder Phase One Participation Agreement and make a one-time \$5,000 payment or obtain a waiver from SPP of the one-time payment.¹ These entities will be eligible to vote on the MPEC and have representatives eligible for appointment to working groups and task forces during phase one consistent with the governance structure described herein. Entities that have load or generation and want to vote in phase one may not execute the Markets+ Market Stakeholder Agreement.

2.2.1.2 PHASE TWO: SPP IMPLEMENTATION

Upon FERC approval of the necessary Markets+ governing documents, SPP will begin acquiring or modifying the necessary software, hardware and related processes if entities commit to fully fund the cost of such efforts. Upon SPP's creation of the Markets+ systems and processes, entities will then be integrated into the system based on participant-specific schedules, including milestones and activation dates.

2.2.1.3 MARKETS+ ADMINISTRATION PHASE

SPP will administer the Markets+ market pursuant to the Markets+ FERC-approved tariff, including a Markets+ Market Participant Agreement and Markets+ Market Stakeholder Agreement. Such agreements will contain terms and conditions that must be met for an entity to be able to participate in Markets+.

1. **Markets+ Market Participant Agreement:** Entities that contribute generation and/or load to the Markets+ market must execute the Markets+ Market Participant Agreement (MPA). Markets+ market participants are eligible to participate in the Markets+ governing structure as a voting entity.
2. **Markets+ Market Stakeholder Agreement:** Entities that do contribute load or generation to the Markets+ market but want to participate in the Markets+ governing structure as a voting entity must execute the Markets+ Market Stakeholder Agreement (MSA) and make an annual payment of \$5,000 or obtain a waiver from SPP of the annual fee.²

Participation in each phase described above is discreet and separate. The incremental approach is taken to confirm an appropriate amount of participant interest and commitment is achieved, while ensuring SPP's costs are recovered for each phase of the effort. The terms

¹ To be eligible for waiver of the one-time phase one participant fee, an entity must provide 1) its Articles of Incorporation or similar documents; 2) its tax exempt status; and 3) its most recent IRS Form 990 or similar documents.

² To be eligible for waiver of the one-time phase one participant fee, an entity must provide 1) its Articles of Incorporation or similar documents; 2) its tax exempt status; and 3) its most recent IRS Form 990 or similar documents.

and conditions for each agreement will be limited to the commitments within scope of each phase.

2.3 ORGANIZATIONAL STRUCTURE

2.3.1 SPP BOARD OF DIRECTORS

2.3.1.1 AUTHORITY

SPP's independent board of directors will provide ultimate oversight of SPP's administration of Markets+ subject to FERC regulatory jurisdiction. The SPP board of directors will give significant recognition and deference to the Markets+ Independent Panel ("MIP") decision-making role.

The SPP board of directors shall review and consider:

1. Decisions of the MIP, after completion of the applicable Markets+ stakeholder process, that have a material adverse effect on SPP, including:
 - a. Material agreements and material changes to those agreements between SPP and Markets+ market participants or SPP and Markets+ market stakeholders
 - b. Issues or concerns raised by the market monitor related to any FERC filing, rule or process within the scope of the market monitor's authority as established by FERC that has been previously raised to the MIP
 - c. Legal and/or litigation disputes or actions involving SPP or the implementation of Markets+
 - d. Financial ramifications or corporate risk to SPP
2. Markets+ budgets, any debt obligations related to Markets+ or material changes to SPP's staffing requirements.
3. Appeals from the MIP made pursuant to Section 3.2.1.

All reviews by the SPP board of directors shall be in coordination with the MIP. Any time the SPP board of directors takes action to review any issue due to a material adverse effect on SPP, the board shall publish the basis for the materiality.

2.3.2 MARKETS+ INDEPENDENT PANEL (MIP)

2.3.2.1 PURPOSE AND SCOPE OF ACTIVITIES

The Markets+ Independent Panel (MIP) is the highest level of authority for decisions related to the Markets+ market with the SPP board of directors providing independent oversight. Actions taken by the MIP under the authorities defined in its charter will be filed with FERC, unless appealed per this section or reviewed by the SPP board of directors pursuant to its authority. Absent an appeal, SPP staff will be authorized to submit requisite regulatory filings to implement the MIP's decision.

Appeals: Any member of the MIP may request the SPP board of directors review any action or inaction of the MIP. Only members of the MIP can appeal to the SPP board of directors. Upon such a request by a member of the MIP, the SPP board of directors shall review the matter for resolution in consultation with the MIP. 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. The MIP is responsible, through the Markets+ State Committee (MSC) and the Markets+ Participants Executive Committee (MPEC) and designated working groups, committees and task forces, for developing and deciding or recommending policies, procedures or system enhancements related to the administration of the Markets+ market.

In carrying out its purpose, the MIP will:

1. Provide a forum for entities that have executed a Markets+ market participant agreement, a Markets+ stakeholder agreement with SPP or a Markets+ non-voting stakeholder to discuss issues related to the ongoing administration and advancement of Markets+ development in the Western Interconnection. The MIP has the authority to set priorities and direct the Markets+ Participant Executive Committee to investigate potential market design and tariff revisions.
2. Approve or reject proposed amendments to the Markets+ tariff made by the Markets+ Participants Executive Committee before the filing of such amendments at FERC.
3. 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. To the extent such rules do apply to the SPP Integrated Marketplace or any other service provided by SPP, the MIP shall be afforded the opportunity to provide input to any other applicable SPP organizational group and the SPP board of directors.
4. Collaborate with SPP staff on the development of Markets+ tariff provisions, market protocols, business practices and interregional agreements to promote transparency and efficiency in the operation of the Markets+ market.

5. Evaluate and provide consultation to SPP on the Markets+ market administration budget to the Markets+ State Committee, Markets+ market participants and Markets+ stakeholders, including modifications or adjustments of the Markets+ market administration rate, in accordance with the Markets+ tariff.
6. Review, consider and decide whether to approve market design system or process enhancement proposals recommended by SPP, the Markets+ State Committee, the Markets+ Participant Executive Committee or any designated working group, committee, or task force established by the Markets+ Participation Executive Committee. Recommendations to enhance systems or processes materially impacting SPP's administration of the Markets+ market or the Markets+ market administration budget must be approved by the MIP before beginning implementation of the enhancement.
7. Resolve any disputes regarding the establishment of a working group or task force and the staffing of that working group or task force.

2.3.2.2 COMPOSITION AND QUALIFICATIONS

The MIP shall consist of five persons, one of which shall be a SPP independent director. The MIP shall select its chair. The members of the MIP shall be independent of any Markets+ market participant, Markets+ market stakeholder or Markets+ non-voting stakeholder and shall not be limited in the number of terms he/she may serve.

Members of the MIP shall have recent and relevant senior management expertise and experience in one or more of the following disciplines: electric industry, including electric transmission and generation planning, markets or general understanding of electric utility regulation.

Members of the MIP shall comply with SPP's standards of conduct. Under the standards of conduct, members of the MIP shall not be an employee, director, consultant or contractor of, and shall have no interest in any third party, or any of its affiliates as defined in SPP's FERC-approved tariff, which shall be deemed to include ownership (outside of a mutual fund, blind trust or similar arrangement as permitted herein) by a panelist or his/her immediate family members of prohibited securities.

2.3.2.3 TERM AND ELECTION

2.3.2.3.1 TERM

Four of the members of the MIP shall be elected at the Markets+ Market Participants and Markets+ Market Stakeholder Forum to a four-year term commencing upon election and continuing until his/her duly elected successor takes office. The initial term for non-SPP directors will be a one, two, three or four-year term to allow staggering. The ballot for the initially elected members of the MIP will consist of a single person for each seat to be filled (slate), and each MPEC member will cast his/her vote to approve or disapprove the entire slate.

2.3.2.3.2 MIP NOMINATING COMMITTEE

2.3.2.3.2.1 Composition

The MIP Nominating Committee will consist of 11 representatives of Markets+ market participants and Markets+ market stakeholders, including one representative from each of the following sectors or groups:

1. Independent power producers
2. Markets+ State Committee member
3. Public interest organizations
4. Cooperatives
5. Municipal utilities, including public utility districts and joint action agencies
6. Federal agencies
7. Investor-owned utilities
8. Competitive marketers
9. Large energy and industrial customers
10. Residential and small commercial retail customers
11. MIP representative, not up for re-nomination, shall serve as chair. For the initial MIP nominations, the chair shall be the SPP independent director designated to serve on the MIP.

Each sector will nominate and vote on its representative to the MIP Nominating Committee.

2.3.2.3.2.2 Meetings

The MIP Nominating Committee shall meet as necessary. 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 and during the selection process of MIP members. Unless otherwise agreed to by the MIP Nominating Committee, representatives shall be given at least 15 business days' written notice of the date, time, place and purpose of each regular or special meeting. Telephone or web conference meetings may be called as appropriate by the chair of the MIP Nominating Committee with at least one business day's prior notice.

2.3.2.3.3 Voting Structure

Decisions of the MIP Nominating Committee shall be by simple majority vote of the representatives participating, whether in person or remotely by telephone, web conference or similar technology and voting. If a representative is unable to attend a meeting, the representative may appoint a proxy from his or her sector to participate in the meeting. The SPP staff secretary will collect and tally the ballots and announce the results of a vote.

2.3.2.3.3 ELECTION PROCESS

1. At least 90 calendar days before the Markets+ Market Participants and Markets+ Market Stakeholders Forum when election of new members of the MIP is required, the MIP Nominating Committee shall commence the process to nominate persons equal in number to the members of the MIP to be elected. The process will include obtaining the services of an executive search firm to conduct a nationwide search for qualified candidates;
2. At least 45 calendar days before the Markets+ Market Participants and Markets+ Market Stakeholders Forum, the MIP Nominating Committee shall determine the persons it nominates for election as members of the MIP, specifying the nominee for any vacancy to be filled. The staff secretary shall prepare the ballot accordingly and shall deliver same to Markets+ market participants and Markets+ market stakeholders at least 30 calendar days before the Markets+ Market Participants and Markets+ Market Stakeholders Forum;
3. For purposes of electing or removing members of the MIP only, each group of Markets+ market participants with affiliate relationships shall be considered a single market participant.
4. 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 the Markets+ Market Participants and Markets+ Market Stakeholders Forum and evidencing support of at least 20% of the existing Markets+ market participants and Markets+ market stakeholders.
 - a. If only one candidate is nominated for a seat, each Markets+ market participants and Markets+ market stakeholders' representative shall be entitled to cast a vote by written ballot, whether in person or remotely by email or other reliable electronic means, for or against the nominee. The votes will be calculated and will require a simple majority. In the event a member of the MIP position is not filled, the MIP Nominating Committee will determine a new nominee for recommendation for election by Markets+ market participants and Markets+ market stakeholders at a special meeting of Markets+ market participants and Markets+ market stakeholders to be held no later than the next regular MPEC meeting.

- b. If multiple candidates are nominated for a seat, each Markets+ market participants and Markets+ market stakeholders' representative shall be entitled to cast a vote by written ballot, whether in person or remotely by email or other reliable electronic means, for only one nominee, but may vote against each candidate. The votes will be calculated with a simple majority of votes cast determining which nominee is elected. In the event a member of the MIP position is not filled, the MIP Nominating Committee will determine a new nominee for recommendation for election by Markets+ market participants and Markets+ market stakeholders at a special meeting of Markets+ market participants and Markets+ market stakeholders to be held no later than the next regular Markets+ market participants and Markets+ market stakeholders meeting.

2.3.2.3.4 VACANCIES

Any member of the MIP may resign by written notice to the MIP and SPP corporate secretary noting the effective date of the resignation. The Markets+ market participants and Markets+ market stakeholders may remove an elected member of the MIP with cause by vote. Removal proceedings may only be initiated by a petition signed by not less than 20% of the Markets+ market participants and Markets+ market stakeholders. The petition shall state the specific grounds for removal and shall specify whether the removal vote is to be taken at a special meeting of the Markets+ market participants and Markets+ market stakeholders or at the next regular meeting of the Markets+ market participants and Markets+ market stakeholders. An external member of the MIP who is the subject of removal proceedings shall be given 15 calendar days to respond to the petition in writing to the MPEC chair and SPP corporate secretary.

If a vacancy occurs, the MIP Nominating Committee will present a nominee to the Markets+ market participants and Markets+ market stakeholders for consideration and election to fill the vacancy for the unexpired term at a special meeting of Markets+ market participants and Markets+ market stakeholders following 30 calendar days' notice from the staff secretary. The replacement member of the MIP shall take office immediately upon election.

2.3.2.4 MEETINGS

Meetings of the MIP are open to all interested parties and written notice of the date, time, place and purpose of each meeting will be provided as described below. However, the MIP may limit attendance during specific portions of a meeting by an affirmative vote of the MIP. Matters for consideration in closed or limited sessions should be limited to personnel, legal and proprietary, confidential or security sensitive information.

At a minimum, meetings will be scheduled such that there will be an official meeting quarterly. Annually, there will be at least one face-to-face meeting.

Written notice and public posting of the date, time, place and purpose of each regular meeting shall be given at least 15 calendar days in advance of each regular meeting. Agendas for regular meetings will be publicly posted no less than seven calendar days before the meeting.

Telephone conference meetings may be called by the MIP chair with prior notice of at least one business day.

2.3.2.5 VOTING STRUCTURE

Decisions of the MIP shall be by simple majority vote of the members participating, whether in person or remotely by telephone, web conference or similar technology and voting, subject to the quorum requirements in Section 3.6. Members of the MIP must be participating at a meeting to vote. No votes by proxy are permitted. The SPP staff secretary will collect and tally the ballots and announce the results of a vote.

2.3.3 COMMITTEES ADVISING THE MARKETS+ INDEPENDENT PANEL

2.3.3.1 MARKETS+ PARTICIPANTS EXECUTIVE COMMITTEE (MPEC)

The Markets+ Participants Executive Committee (MPEC) will provide a forum for Markets+ market participants, Markets+ market stakeholders and Markets+ non-voting stakeholders to discuss issues related to the ongoing administration and advancement of market development in the Western Interconnection.

The MPEC will review system or process enhancement proposals recommended by SPP, the Markets+ State Committee, the Markets+ market participants, Market+ stakeholders, Markets+ non-voting stakeholders or any designated working group, committee or task force established by the MPEC. The MPEC will provide to the MIP its recommendation on proposals received for the MIP's consideration and decision. The MPEC recommendations to the MIP are advisory and non-binding. In its presentation to the MIP, the MPEC will report any minority views expressed to the MPEC during its consideration. Recommendations to enhance systems or processes materially impacting SPP's administration of the Markets+ market or the Markets+ market administration budget must be approved by the MIP before beginning implementation of the enhancement.

2.3.3.1.1 COMPOSITION

Each Markets+ market participant and Markets+ market stakeholder shall appoint one representative to the MPEC. Each representative designated shall be a senior level management employee with financial decision making authority. The MPEC representatives will appoint the chair and vice chair. Each representative of the MPEC may continue to be a representative thereof until the Markets+ market participant appoints a successor representative. A Markets+

market participant and Markets+ market stakeholder shall be eligible to appoint only one representative for itself.

2.3.3.1.2 AUTHORITY

The MPEC will have authority to make recommendations to the MIP regarding:

- Proposed amendments to the Markets+ tariff
- Markets+ market protocols to support the filed tariff
- The administrative rate charged to participants of the Markets+ market

The MPEC may establish standing working groups and ad hoc task forces as needed to facilitate its authorities as described below.

2.3.3.1.3 MEETINGS

Meetings of the MPEC are open to all interested parties and written notice of the date, time, place and purpose of each meeting will be provided as described below. However, the MPEC may limit attendance during specific portions of a meeting by an affirmative vote of the MPEC. Matters for consideration in closed or limited session should be limited to personnel, legal and proprietary, confidential or security sensitive information.

At a minimum, meetings will be scheduled such that there will be an official meeting quarterly. Annually, there will be at least one face-to-face meeting.

Written notice and public posting of the date, time, place and purpose of each regular meeting shall be given at least 15 calendar days in advance of each regular meeting. Agendas for regular meetings will be publicly posted no less than seven calendar days before the meeting.

Telephone conference meetings may be called by the MPEC chair with prior notice of at least one business day.

2.3.3.1.4 VOTING STRUCTURE

Upon execution of the Markets+ participant agreement or execution of the Markets+ stakeholder agreement and payment of the annual fee or fee waiver,³ an entity will be assigned to one of three membership sectors: Investor-owned utilities, public power and independent. The sectors are defined as follows:

³ Or execution of the Markets+ Market Participant Phase One Funding Agreement or Markets+ Market Stakeholder Phase One Participation Agreement and payment of the one-time fee or fee waiver.

Investor-owned utilities (IOUs): This sector includes Markets+ market participants that are public utilities under the Federal Power Act, regulated by one or more state regulatory commission and subject to a fiduciary responsibility to investors to earn a return on rate-based assets. Votes in this sector will be calculated based upon load-ratio share. Additionally, depending on which entities join Markets+ phase one, each Markets+ market participant in this sector may be assigned to a geographic region for voting purposes.

Public power: This sector includes Markets+ market participants that are publicly-owned utilities, electric cooperatives and power marketing administrations (PMAs). Votes in this sector will be calculated based upon load-ratio share. Additionally, depending on which entities join Markets+ phase one, each Markets+ market participant in this sector may be assigned to a geographic region for voting purposes.

Independents: This sector includes Markets+ market participants that are not an IOU or a public power utility (including independent power producers and marketers of electrical power) and Markets+ market stakeholders. The votes for this sector will be divided such that those entities contributing generation to the Markets+ market will receive 2/3 of the sector vote and those without generation to contribute to the Markets+ market will receive 1/3 of the sector vote.

Each sector's vote will be calculated separately with the result for that sector being a percent of approving vote to the total number of participants in the sector voting. Each of the three sectors represents 33 1/3% of the vote. An action is approved by the MPEC if the average of these percentages is at least 67%, and if geography is used, the average of the geographic regions is at least 50%.

2.3.3.2 MARKETS+ STATE COMMITTEE (MSC)

2.3.3.2.1 COMPOSITION/MEMBERSHIP

One representative from each state in which a Markets+ market participant has generation or load participating in the Markets+ market in that state may participate as a member of the Markets+ State Committee (MSC). Each state representative will be appointed by the utility regulatory commission of that state.

The MSC shall have the discretion to determine participation of representatives from other state agencies, including state energy offices, state environmental offices and state consumer advocates, in the MSC's governing structure.

The MSC will provide advice to the MIP, the MPEC and any working group or task force on all matters pertinent, including but not limited to, initiative prioritization and policy issues, to the participation in the Markets+ market of the Markets+ market participants under the Markets+ tariff. SPP staff will assist the MSC by providing information and support relevant to the Markets+ market. Members of the MSC and other state officials (state energy offices, state environmental offices, state consumer advocates, etc.) are eligible for appointment to Markets+ task forces.

2.3.3.2.2 MEETINGS AND VOTING

The MSC will determine its meeting provisions and voting structure.

2.3.3.2.3 SUPPORT AND FUNDING

SPP will facilitate the retention of independent staffing for the MSC sufficient and stable enough to support the MSC's ability to develop analytical and legal analysis in order to present independent positions related to the Markets+ market and before FERC. The MSC shall annually submit a proposed budget to the MIP for approval. Before approval, the MIP shall seek comment from the MPEC. The approved MSC budget costs will be allocated to the Markets+ market participants.

2.3.3.2.4 DATA ACCESS

The MSC will have access to performance data and data specific to policy initiatives, subject to any confidentiality agreements.

2.3.4 OTHER COMMITTEES AND STAKEHOLDER GROUPS

2.3.4.1 MARKETS+ WORKING GROUPS

Through an affirmative vote in accordance with the voting structure set forth in Section 2.3.3.1.4, the MPEC may establish standing working groups to assist with its mission. Before voting on the establishment of a working group, the MPEC should consider potential resource and financial impacts in excess of those contemplated.

2.3.4.1.1 COMPOSITION AND TERMS

Unless otherwise provided in these bylaws, each working group shall have a chair to preside over meetings. The chair of all organizational groups shall be nominated by the MPEC for consideration and appointment by the MIP. The term of the chair of all working groups shall be two years. Working groups have discretion to determine the need for a vice-chair. Should a working group establish a vice-chair position, the vice-chair shall be elected by the working group.

Following a solicitation of nominations by SPP staff, working group representatives shall be recommended by SPP staff to the MPEC for approval. The recommendation and approval of representatives shall consider the various types and expertise of Markets+ Market Participants (MMPs) and Markets+ Market Stakeholders (MMS) and their geographic locations to achieve a widespread and effective representation of MMPs and MMSs. Criteria and sector representation for serving on a working group will be determined in the group's scope. An appointment to a working group is for an individual, not a corporate entity.

2.3.4.1.2 MEETINGS

Working groups shall meet as necessary and the meetings shall be open. However, any working group may limit attendance at a meeting by an affirmative vote of the working group. Matters for consideration in closed or limited attendance session should be limited to personnel, legal and proprietary, confidential or security sensitive information. Unless otherwise agreed to by the working group, representatives shall be given at least 15 business days' written notice of the date, time, place and purpose of each regular or special meeting. Telephone or web conference meetings may be called as appropriate by the chair of any working group with at least one business day's prior notice.

2.3.4.1.3 VACANCIES

Working group vacancies will be filled on an interim basis by appointment of the MPEC chair.

2.3.4.1.4 VOTING STRUCTURE

Each representative of a working group shall have one vote. A simple majority of representatives, whether participating in person or remotely by telephone, web conference or similar technology or represented by proxy and voting, shall be required for approval of an action. Unless otherwise stated, a working group may determine to vote on an issue by email. The outcome of any email vote must be recorded in the minutes for the group.

The quorum for any working group shall be a majority of the representatives thereof, but not less than three representatives, provided a lesser number may adjourn the meeting to a later time. The quorum for a meeting must be established and maintained throughout the meeting in order for the working group to take any binding action(s). Notwithstanding the above, any actions taken before a quorum is lost are considered valid and binding.

2.3.4.2 STANDING COMMITTEES

2.3.4.2.1 OPERATIONS AND RELIABILITY WORKING GROUP (ORWG)

Provides recommendations to other working groups and the MPEC on the effects of current or proposed market designs on these entities' ability to ensure reliable operations. The ORWG will be comprised of one representative from each Markets+ market participant that is a balancing authority or transmission provider.

2.3.4.2.2 MARKET WORKING GROUP (MWG)

Reviews any initiative that would modify the Markets+ tariff or market protocols.

2.3.4.2.3 SEAMS WORKING GROUP (SWG)

Coordinates with the ORWG, any RTO or ISO adjacent to the Markets+ footprint and any bordering non-RTO or ISO balancing authority areas and transmission providers.

2.3.5 AD HOC TASK FORCES

A temporary task force may be proposed by the MPEC chair or working group chair and approved by the MPEC or applicable working group through an affirmative vote in accordance with the voting structure set forth in Section 2.3.3.1.4. Upon establishment of a task force reporting to the MPEC or a working group, the MPEC chair or working group chair shall appoint a chair of the task force to preside over meetings. All ad hoc task forces shall be temporary and shall have the scope of its activities limited to a specific purpose. Before the establishment of an ad hoc task force, the MPEC chair or working group chair should consider any potential resource and financial impacts in excess of those contemplated.

2.3.5.1 COMPOSITION AND TERMS

Task force representation will be appointed by the MPEC chair or working group chair after the applicable staff secretary solicits nominations for task force members. The MPEC chair or working group chair, in coordination with SPP staff, shall consider the various types and expertise of Markets+ Market Participants (MMPs) and Markets+ Market Stakeholders (MMS) and their geographic locations to achieve a widespread and effective representation of the MMPs and MMSs. Representatives from the MSC, state energy officers and state consumer advocates are also eligible to serve on task forces. Criteria and sector representation for serving on a task force will be determined in the group's scope. An appointment to a task force is for an individual, not a corporate entity.

2.3.5.2 MEETINGS

Task forces shall meet as necessary and the meetings shall be open. However, any task force may limit attendance at a meeting by an affirmative vote of the task force. Matters for consideration in closed or limited attendance session should be limited to personnel, legal and proprietary, confidential or security sensitive information. Unless otherwise agreed to by the task force, representatives shall be given at least 15 business days' written notice of the date, time, place and purpose of each regular or special meeting. Telephone or web conference meetings may be called as appropriate by the chair of any task force with at least one business day's prior notice.

2.3.5.3 VACANCIES

Task force vacancies will be filled on an interim basis by appointment of the MPEC chair or working group chair.

2.3.5.4 VOTING STRUCTURE

Each representative of a task force shall have one vote. A simple majority of representatives, whether participating in person or remotely by telephone, web conference or similar technology, or represented by proxy and voting, shall be required for approval of an action. Unless otherwise stated, a task force may determine to vote on an issue by email. The outcome of any email vote must be recorded in the minutes for the group.

The quorum for any task force shall be a majority of the representatives thereof, but not less than three representatives, provided a lesser number may adjourn the meeting to a later time. The quorum for a meeting must be established and maintained throughout the meeting in order for the task force to take any binding action(s). Notwithstanding the above, any actions taken before a quorum is lost are considered valid and binding.

2.3.6 SPP STAFF INDEPENDENCE AND SUPPORT

Each working group, committee or task force reporting to the MPEC shall be assigned a SPP staff member who shall attend all meetings and act as secretary to the group. Staff secretaries of all committees, working groups and task forces shall be non-voting, independent and impartial. The secretary shall keep minutes of pertinent discussions, business transacted, decisions reached and actions taken at each meeting. Minutes shall be published within seven calendar days following a meeting but in any event in advance of the next meeting and considered final documents upon their approval by the working group, committee or task force.

SPP shall strive to provide support to all working groups, committees and task forces while taking into account the Markets+ market administration budget and other priorities of the SPP organization. Should it become necessary for SPP to hire additional staff or augment staffing to maintain the expected level of support, SPP will advise the MIP and MPEC of any budgetary impacts.

2.3.7 ATTENDANCE, QUORUM AND PROXY

If a representative is unable to attend a meeting of the MPEC, a working group or task force, he/she may, in writing to the applicable chair, vice chair and staff secretary, appoint a proxy representative who shall have such rights to participate and vote as the representative specifies. The proxy representative may be another member of the MIP, MPEC or the committee, working group or task force or another person who has the authority to act on behalf of the representative. Members of the MIP must be participating at a meeting to vote. No votes by proxy are permitted.

The quorum for a meeting of the MIP, the MPEC, the MSC or any working group, committee or task force shall be a majority of the representatives thereof, provided a lesser number may adjourn the meeting to a later time. A representative participating by phone is considered to be in attendance of the meeting for the purpose of quorum. The quorum for a meeting must be

established and maintained throughout the meeting in order for the group to take any binding action(s). Notwithstanding the above, any actions taken before a quorum is lost are considered valid and binding. A proxy will serve to meet the quorum requirements as follows:

- A proxy provided to another representative of the MPEC will not be recorded as attendance at the meeting and will not serve to meet or maintain the quorum requirements.
- A proxy provided to another person with the authority to act on behalf of the representative will be recorded as attendance at a meeting for the purpose of meeting or maintaining the quorum requirements.

2.3.8 APPEALS TO THE MPEC AND THE MIP

Should any Markets+ market participant, Markets+ market stakeholder or the MSC disagree on an action or inaction taken or recommended by any working group or task force, such Markets+ Market participant, Markets+ Market stakeholder or the MSC may, upon written request to the MPEC staff secretary, appeal and submit an alternate recommendation, including a recommendation for inaction to the MPEC within seven calendar days after the meeting following such working group or task force action or inaction. The MPEC shall timely consider and take any action it deems necessary to address the appeal.

Should any Markets+ market participant, Markets+ market stakeholder or the MSC disagree on the MPEC's action on any issue, such Markets+ market participant, Markets+ market stakeholder or MSC member may, upon written request to the MIP staff secretary, appeal and submit an alternative recommendation to the MIP within seven calendar days after the meeting following the MPEC action.

The MIP shall timely consider and take any action it deems necessary to address the appeal. This could include affirming the action or inaction appealed, reversing the action or inaction appealed or remanding the matter back to the appropriate group or groups.

2.4 GOVERNANCE REVIEW

2.4.1 MARKETS+ PHASE ONE GOVERNANCE REVIEW

Before the conclusion of phase one, the MPEC shall conduct a review and assessment of the MPEC's voting structure used during phase one and report any findings to the SPP board of directors subcommittee. This review and assessment may include recommended changes to the MPEC's voting structure to be included in SPP's filing the Markets+ proposal with the FERC for approval.

2.4.2 MARKETS+ GOVERNANCE REVIEW

- Upon the MPEC's request, and subject to approval by the MIP, but no later than three years after the Markets+ market launch, the MIP will initiate a review of the Markets+ market governance in light of accumulated experience and changed circumstances.
- Voting structure changes: Findings and a request by the MPEC that participation and voting experiences suggest that changes in voting structures are needed.
- Markets+ service offering evolution and Markets+ State Committee authority: SPP Bylaws confer on the RSC certain authorities and responsibilities within the governance of SPP. Specifically, Section 7.2 of the SPP Bylaws gives the RSC specific authority (pursuant to Section 205 of the Federal Power Act) over:
 - Cost allocation
 - Financial transmission rights
 - Planning for remote resources
 - Regional resource adequacy

While none of these authorities are part of the Markets+ service offering at this time, if the market design evolves to include these features, the MIP will evaluate whether the MSC should have similar designated authorities.

2.4.3 GOVERNANCE REVIEW PROCESS

To accomplish the governance review described in Section 2.3.9.2, after a solicitation of nominations, the MIP shall appoint a sector-based working group to develop recommendations for any governance revisions. Any recommended revisions identified by the working group shall be presented to the MPEC for consideration and recommendation before being presented to the MIP for approval. Any modification to Markets+ governance requires a super majority (4/5th vote) of the MIP.

3.0 MARKET DESIGN

For the purposes of this service offering, SPP's Markets+ design is specific to the full day-ahead market proposal. In November 2022, some parties in the Markets+ footprint expressed interest in participating in an energy imbalance only market design, referred to as Markets+ real-time. The details, scope and timeline for that potential service is separate and not included in this

service offering. More details about the possibility of launching a Markets+ real-time structure ahead of this full day-ahead market proposal will be explored in the coming months.

3.1 MARKETS+ OVERVIEW

As a market operator⁴, SPP collaborates with participating entities, serving as an interface between reliability and commercial functions in the Markets+ footprint. To assist in reliable operations and competitive wholesale electricity prices, SPP proposes to operate and administer energy and reserve markets. The responsibilities to capacity adequacy, reserves and other reliability-based concerns do not change because of this proposed market.

3.1.1 ENERGY AND RESERVE MARKETS

The energy and reserve markets processes include market participant⁵ participation in:

- A price-based day-ahead market (DA market) with congestion rent allocation in the DA market
- A price-based real-time balancing market (RTBM)
- All reliability unit commitment (RUC) processes

The DA market provides market participants with the ability to submit offers to sell energy, flexibility reserve products⁶ and/or to submit bids to purchase energy. The RTBM provides market participants with the ability to submit offers to sell energy and flexibility reserve products. Energy and reserve markets operations will simultaneously or jointly optimize resource offers for energy and reserve in the security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) algorithms. The objective function of joint optimization is the minimization of the total production costs in the DA market and the RTBM for energy and reserve products to meet the requirements.

Procurement of operating reserve (regulation-up service, regulation-down service, spinning reserve and supplemental reserve) will not be included in the energy and reserve markets but will continue to occur under the existing paradigm. Market participants with resources providing

⁴ NERC Reliability Functional Model – Version 5.1; The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

⁵ An entity that generates, transmits, distributes, purchases, or sells electricity within, into, out of, or through the transmission system participating in Markets+.

⁶ Flexibility Products refers to energy reserve products developed to respond to uncertainties or unexpected changes primarily due to renewable and load forecast errors. Further discussion in later sections.

operating reserve will communicate operating reserve procurements to SPP to ensure the energy and reserve markets do not optimize capacity set aside for those operating reserve obligations.

The simultaneous optimization logic considers various permutations of unit commitment and the joint dispatch of energy and flexibility reserves, resulting in a solution with the least overall production cost subject to reliability constraints. If multiple flexibility reserve products are defined, the simultaneous optimization logic allows product substitution of flexibility reserve if economically efficient, i.e., the logic utilizes a higher quality product offer to fill a lower quality product demand if and when such selection would reduce the overall production cost compared to a situation where each product was cleared separately.

SPP performs the RUC processes to ensure the physical unit commitment produced from the DA market is sufficient to meet SPP-projected capacity needs during the operating day. Exhibit 1-1 provides an overview of the key energy and operating reserve market functions.

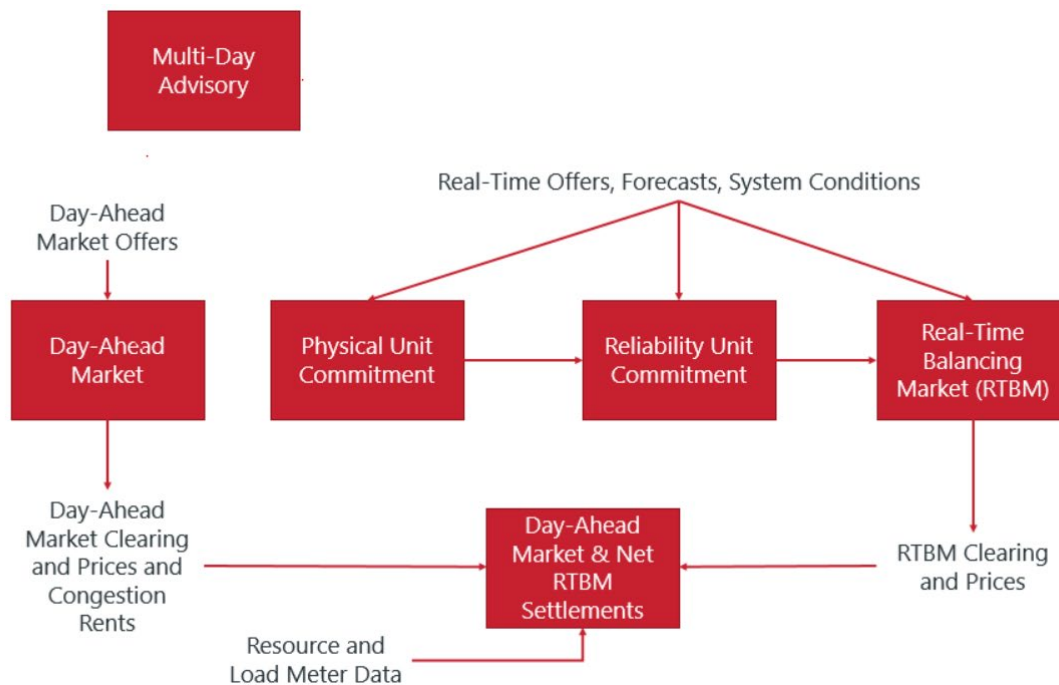


EXHIBIT 1: OVERVIEW OF KEY ENERGY AND OPERATING RESERVE MARKET FUNCTIONS

Key features of the day-ahead market include:

- A financially binding market in which all cleared supply and demand is settled with a minimum mandatory offer quantity requirement⁷.
- Physical supply offers, virtual supply offers, physical demand bids and virtual demand bids are accommodated⁸.
- Import, export and through-interchange transactions are accommodated in Markets+, resulting in energy supply or energy demand cleared at external interface settlement locations as appropriate.
- DA market clearing is performed for energy and flexibility products on a least-cost, co-optimized basis and accounts for each resource's marginal system losses, congestion and energy cost to minimize the overall production cost.
- All physical supply cleared for flexibility reserve products cleared are paid at the applicable market clearing price for the flexibility reserve product.
- All cleared energy supply is paid at the settlement location⁹ DA market locational marginal price, and all cleared energy demand is charged at the settlement location DA market locational marginal price, producing an over collection due to congestion (congestion revenues) and marginal losses (marginal loss revenues).
- Firm¹⁰ transmission service reservation (TSR) holders are paid DA congestion rents. DA marginal congestion component (MCC) is collected for all load, generators, imports and exports. The sum of this number is allocated back to TSR holders.
- Losses will settle under the host transmission service provider with any impacts of losses reduced from Markets+ settlements to avoid double settlement of losses.
- Resources committed by SPP are assured recovery of their startup offer, no-load offer and actual incremental energy costs as defined in the energy offer curve, subject to certain eligibility criteria.

⁷ Specific details of minimum mandatory offer requirement will be determined in Phase 1 of Markets+ development.

⁸ SPP and stakeholders may delay virtual supply offers and virtual demand bids for a period of time after Markets+ Launch. Details will be determined in Phase 1.

⁹ Settlement locations are the location of finest granularity for calculation of settlements in Markets+. SPP anticipates multiple types of Settlement Locations including: Resources, Load, Trading Hub, Resource Hub, and External Interfaces.

¹⁰ The design can also contemplate allocating day-ahead congestion rents to conditional firm and secondary network transmission service, but more discussion is needed on the appropriateness and level of allocation for curtailment priority 6 reservations.

- Flexibility reserve procurement costs are allocated and collected on a reserve zone basis.
- Robust greenhouse gas (GHG) pricing and dispatch included in the market optimization that accounts for zones with and without formal GHG programs, including providing the necessary tracking and reporting associated with supply serving load in any state requiring formal tracking. More details of the GHG proposal are included later in this service offering.

Key features of the RUC processes and real-time balancing market include:

- The RUC may commit resources based on market participant offers from physical resources that were not otherwise committed by the day-ahead process.
- The RTBM operates on a five-minute basis, calculates dispatch instructions for energy, clears flexibility products on a least-cost, co-optimized basis and accounts for each resource's marginal system losses, congestion and energy costs to minimize the overall production cost.
- Cleared flexibility reserve settlement is performed on a five-minute basis. SPP calculates charges and credits as the difference between the RTBM flexibility reserve megawatts (MW) cleared and the DA market flexibility reserve MW cleared amount multiplied by the applicable flexibility reserve market clearing price.
- Resource settlement is performed on a five-minute basis. SPP calculates energy charges and credits as the difference between the resource actual output and the resource DA market cleared MW amount multiplied by the settlement location RTBM locational marginal price.
- Load settlement is performed on a five-minute basis. SPP calculates energy charges and credits as the difference between the load actual consumption and the load DA market cleared MW amount multiplied by the settlement location RTBM locational marginal price.
- Import, export and through-interchange transaction energy settlement is performed on a five-minute basis. SPP calculates charges and credits as the difference between the real-time scheduled MW amount and the DA market cleared MW amount multiplied by the RTBM locational marginal price of the appropriate external interface settlement location.
- Losses will settle under the host transmission service provider with any impacts of losses reduced from Markets+ settlements to avoid double settlement of losses.
- Resources committed by SPP are assured recovery of their startup offer, no-load offer and actual incremental energy costs as defined in the energy offer curve subject to certain eligibility criteria.

- Charges are imposed on market participants for failure to deploy energy as instructed.
- Flexibility reserve procurement costs and net of penalty revenues received for flexibility reserve availability failure are collected from market participants on a real-time, load-ratio share basis.

Exhibit 1-2 provides a timeline-based illustration of the sequencing and interaction of the key energy and operating reserve market functions for a representative operating day (1/31).

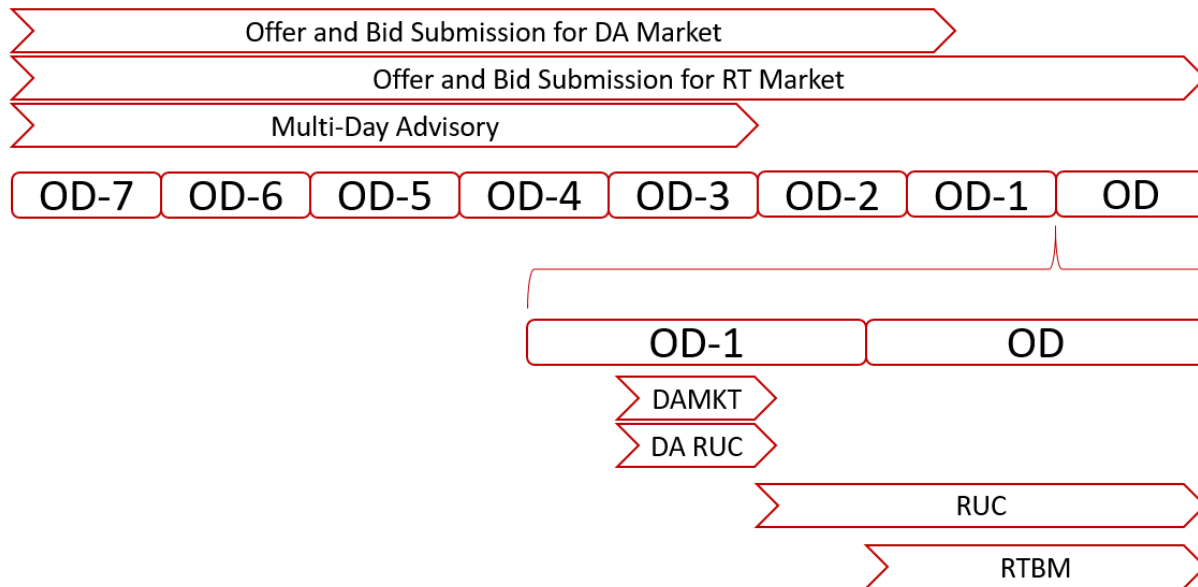


EXHIBIT 2: ENERGY AND RESERVE MARKETS PROCESSES TIMELINE

3.1.2 CONGESTION RENT ALLOCATION

Unlike a full RTO/ISO, Markets+ will not include financial transmission rights (FTRs), in the traditional sense, where eligible entities can buy or sell FTRs through a market clearing process. Instead, Markets+ will use transmission service rights of Markets+ as the basis for allocating congestion rent revenues collected by SPP in the day-ahead market. This allocation approach leverages the existing open access transmission tariff (OATT) framework to ensure entities who secure OATT rights to physically deliver power across constrained paths can receive the maximum economic value and the economic value of long-term OATT rights continues to be recovered by the transmission customers who invest in those rights (and fund the underlying facilities). Achieving these objectives will provide confidence to transmission customers that they will continue to receive the economic value of their existing rights while also preserving

incentives for continued investment in long-term OATT service in the future. These outcomes support the broader goal of preserving third-party revenues recovered by transmission service providers (TSPs) through sales of long-term OATT service and minimize the risk of cost shifts onto the native load customers of TSPs that join Markets+.

SPP's proposed congestion rent allocation approach is based on transmission rights rather than transmission schedules. This approach ensures transmission customers will receive the economic value of their rights without the need to self-schedule their own resources or loads using their own transmission reservations. Instead, it provides a powerful incentive for the transmission customer to allow the market to make the most efficient use of the transmission as part of its broader economic optimization while providing assurance that the resulting congestion value will be allocated to the appropriate customer(s).

3.1.3 FINANCIAL SETTLEMENTS

Markets+ incorporates full net-settlement of market activity for each operating day. Post-operating day activities begin on the day immediately following the operating day. SPP will issue scheduled settlement statements for each operating day to market participants. Settlement invoices are issued to market participants on a weekly basis.

Exhibit 1-3 provides a representative overall timeline of post-operating day activities.

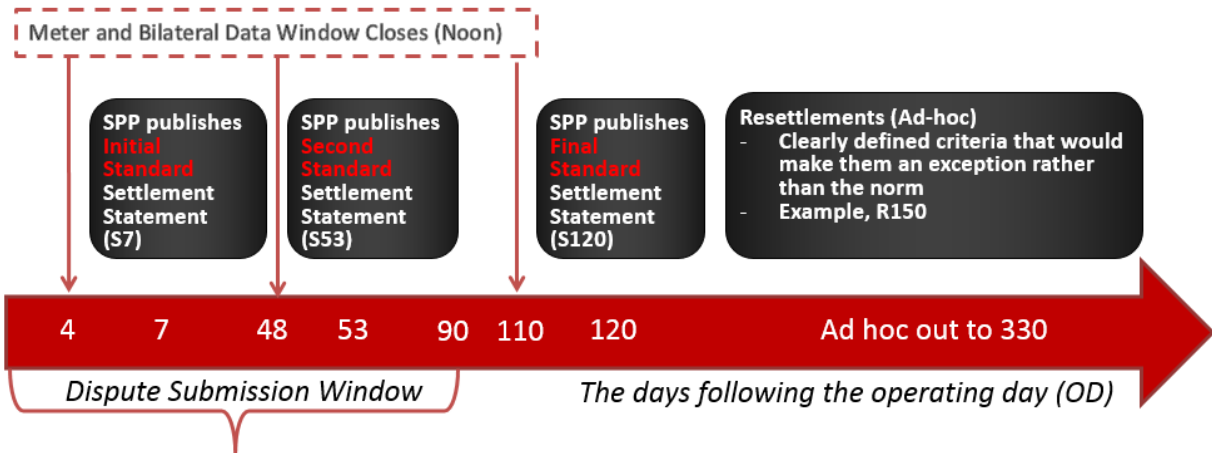


EXHIBIT 3: POST OPERATING DAY ACTIVITIES TIMELINE

3.2 OVERVIEW MARKET PARTICIPANT RESPONSIBILITIES

To participate in Markets+, an entity must be a balancing authority or receive balancing authority services from a balancing authority participating in Markets+, i.e., a participating balancing authority¹¹. An entity participating in Markets+ will have the opportunity to fully participate in Markets+ (i.e., register assets, submit offers, financially settle with SPP, make available transmission capabilities when appropriate, etc.). SPP will develop a more specific list of market participant opportunities and requirements during phase one, but the guiding principle is entities can directly participate in Markets+ if willing and would not be required to participate through an intermediary.

SPP anticipates significant coordination and collaboration between the participating balancing authorities and the market operator. SPP proposes a taskforce or stakeholder group be established during phase one to determine what, if any, additional requirements and responsibilities are required for participating balancing authorities.

3.2.1 METERING REQUIREMENTS

Participants in Markets+ must designate an entity, including but not limited to itself, to provide revenue-quality meter data to SPP for use in Markets+ settlement processes.

¹¹ SPP and stakeholder will investigate the benefits of an external resource participation model during Phase 1.

SPP proposes stakeholders determine the detailed, technical meter protocols¹² during phase one based on the regional preferences and standards of the anticipated Markets+ footprint. SPP strongly encourages a two-part technical metering requirement for Markets+. Any existing metering equipment at the time a participant integrates into Markets+ is acceptable if the participant is **capable of providing at least hourly kilowatt-hour-interval data information**. Any new or replacement metering equipment must satisfy the technical requirements to be determined in the next phase of detailed market design. SPP finds this two-phased metering approach to be successful in market launches, striking a balance between uniformity in metering equipment and reducing unnecessary barriers to participant entry. Stakeholders will determine the identification of the entity responsible for enforcing Markets+ technical meter protocols during phase one.

3.2.2 REGISTRATION REQUIREMENTS

SPP requires participants in Markets+ to register their loads and resources within¹³ a participating balancing authority. SPP uses registration data for operation and settlement of Markets+, determining responsibilities and identifying discrete entities.

Participants must register all resources in a participating balancing authority on a nodal basis. Participants may register resources located at the same physical and electrically equivalent injection point on the transmission system individually or as an aggregate. SPP proposes that resources interconnected to the transmission system with a maximum output below a de minimis threshold, e.g., 100 KW, be prohibited from registering in Markets+. SPP proposes **behind-the-meter generation¹⁴ of substantial capacity be required to register in Markets+, and the same threshold requirement be for the entire Markets+ footprint. SPP proposes the specific size requirement for behind-the-meter generation be determined in phase one but would expect the size to be between five to 10 MW.**

Participants must register all load, either individually at each point of withdrawal from the transmission system or in aggregate, grouping multiple withdrawal points into a single aggregate location of financial settlement. Each participant must identify any nonconforming¹⁵ load or load associated with demand response participating in Markets+.

¹² The detailed, technical meter protocols will include requirements for timing standards, measurement quantities, accuracy, testing, and technology-specific requirements for different meter types.

¹³ This includes load and resources pseudo-tied into a Participating Balancing Authority, but does not include load and resources pseudo-tied out of a Participating Balancing Authority.

¹⁴ A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy.

¹⁵ Non-conforming load is more process driven and needs to be separated from the load forecast application because it does not follow a predictable pattern and introduces error to the load forecast produced by SPP for Markets+ processes.

3.3 MARKET OPERATOR RESPONSIBILITIES

3.3.1 LOAD AND RESOURCE FORECASTING

SPP will develop short-term and midterm load forecasts for each balancing authority in the Markets+ footprint. SPP will develop the short-term load forecast on a rolling five-minute basis for the next three hours to use as an input for the real-time balancing market and short-term, 15-minute granularity reliability unit commitment. SPP will develop the midterm load forecast on a rolling hourly basis for the next seven operating days to use as an input for all hourly unit commitment processes.

SPP produces and updates hourly wind and solar-powered generation forecasts on a rolling 48-hour bases to use as an input for all hourly unit commitment processes.

The individual wind and solar-powered generation forecasts may be available to individual market participants and their designated agents, subject to any confidentiality protections. SPP proposes to make available to all participants the aggregate summations of the solar and wind-powered generation forecasts, with historical data available shortly after real time for a determined period of time.

During phase one, SPP will work with stakeholders to determine if there are benefits to providing an option where participants can submit load or resource forecasts for use in Markets+ in place of the SPP developed forecast.

3.3.2 MARKET SYSTEM AVAILABILITY

SPP can provide a highly reliable and secure Markets+ solution.

SPP maintains a tier III¹⁶ data center and requires software to adhere to SPP security policies to meet cybersecurity requirements to ensure reliability and security. Physical security of SPP's data center is a priority. Data centers are strictly monitored and have 24/7 security guards. SPP conducts regular security assessments and has a team dedicated to cybersecurity.

Both of SPP's geographically separate data centers are fully equipped with redundant circuits, telecommunications and networking. As is typical for systems and applications used by SPP, applications used for Markets+ will be housed in both data centers, with one serving as primary and the other as secondary. Should an issue occur in the primary data center, processing can be moved to utilize the secondary data center while the primary is restored to full functionality, after which processing would return to the primary data center.

¹⁶ As rated by the Uptime Institute.

3.4 MARKETS+ MARKET DESIGN KEY FEATURES

3.4.1 MARKET PRODUCTS

3.4.1.1 ENERGY

Energy is the primary product for Markets+ and will be cleared in order to balance generation with expected obligations. For Markets+, energy is defined as an amount of electricity that is bid or offered, produced, purchased, consumed, sold or transmitted over a period of time, which is measured or calculated in megawatt hours (MWh). Financially binding clearings of energy will occur on an hourly granularity in the DA market and five-minute granularity in the RT market. Energy will be settled at the corresponding settlement location's locational marginal price (LMP). As the market operator, SPP will issue energy deployment instructions to dispatchable resources in the Markets+ footprint.

Before implementation, participants should decide the course of action when the market cannot balance both supply and demand, along with the distinct roles and responsibilities of the market operator and the balancing authority operator in those circumstances. It is common to have a high penalty value that guides the market software to treat the power balance as one of the most important constraints (see the Price Formation section). The design needs to specify whether an administrative pricing associated with power balance will lead to high prices during scarcity.

3.4.1.2 FLEXIBILITY RESERVES

Organized energy markets use flexibility reserve products to respond to uncertainties or unexpected changes primarily due to renewable and load forecast errors. These products increase the security of the grid and allow for fewer shortages and pricing excursions. Incorporating flexibility reserve products both value and put a price on the increasingly important attribute of flexibility under both normal and stressed conditions. One or more flexibility products may exist that target different periods, depending on regional preference and system need.

A short-term flexibility product targets periods in the intra-hour range (e.g., 10 to 30 minutes). Depending on the volatility and forecast uncertainties in this time range, a flexibility product helps minimize price volatility resulting from transient error (i.e., temporary scarcity resulting from the RT market looking at too narrow a window of time absent the product) and reduces the risk of the RT market not meeting other future obligations. For this horizon, online dispatchable resources would be the primary resources considered for clearing, but offline faster-starting resources could also clear, if desired.

A longer-term flexibility product could target periods beyond real time (e.g., one hour or greater). Depending on the potential uncertainties over this longer horizon, a flexibility product

helps ensure reliability and reduces out-of-market manual actions. Both online and offline resources would be the primary resources considered for clearing.

The variability and forecast uncertainties of the anticipated footprint determine the potential benefit of implementing flexibility products. Given the current and expected renewable integration plans for most of the Western Interconnection, SPP proposes both short-term and longer-term flexibility products be included in Markets+. SPP recommends any flexibility product design include co-optimization and clearing in DA market and RT market studies while accounting for those product requirements in any incremental commitment during the RUC processes. SPP and Markets+ participants will perform analysis to determine the detailed design once the anticipated Markets+ footprint is determined. This analysis will include:

- Number of required products (e.g., short-term, long-term, both or more) to address uncertainty needs. SPP expects that there would be flexible reserves procured as part of the day-ahead market optimization, with procurement volumes adjusted in the real-time market as grid conditions become clearer.
- How scarcity of the products should be addressed (e.g., demand curve).
- Composition of the demand curve (i.e., sloped or block-based, actual scarcity prices).
- The time horizon for the products (e.g., 20 minutes for short-term flexibility and two hours for long-term flexibility).
- Which resources can participate and whether costs are based on lost opportunity, offers, both or some other methodology.
- Cost allocation to fund credits paid to resources providing the product.
- Calculation methodologies for system wide and zonal procurement requirements.

SPP proposes flexibility product requirements be determined based on the needs of the overall Markets+ footprint, recognizing the diversity benefit of the regional market.

3.4.1.3 OPERATING RESERVES

Operating reserves include regulation and contingency reserves. Regulation reserves are a reservation of qualified resource capacity in the up and down direction and are used to balance real power requirements on a short-term, continuous basis. Contingency reserves are a reservation of qualified resource capacity in the up direction and are used primarily to recover from resource contingencies. For the initial scope of Markets+, SPP proposes regulating and contingency reserves not be cleared in Markets+, and instead, the procurement, deployment and compensation for these services remain under the participating balancing authorities.

Operating reserves are maintained by the balancing authority. SPP and stakeholders could investigate enhancements to optimize operating reserves within a participating BA as a post go-live enhancement.

Since Markets+ will not procure, deploy or set prices for operating reserves, it is necessary for participants to communicate the capacity allocated to contingency and regulating reserves to reserve capacity and prevent the simultaneous clearing of other products or reserves with those same MWs. As the market operator, SPP will not issue deployment instructions for operating reserves, but the real-time balancing market should be aware of ongoing deployments to ensure the centralized unit dispatch and balancing authority actions are complementary and do not contribute to unforeseen risks to reliability. Depending on the design, SPP may need to be aware of MWs coming from the deployment of reserves if those MWs are not to be subjected to LMP settlements.

3.4.1.4 FLEXIBILITY RESERVE ZONES

SPP proposes zonal delivery constraints for flexibility reserves be included in the design for Markets+ given the existing interface and deliverability limitations present in the Western Interconnection. Flexibility reserve zones and the corresponding zonal constraints will ensure Markets+ commitment and dispatch decisions result in flexibility reserves that are geographically diverse and deliverable.

A reserve zone is a specific group of Pnodes for which a minimum and maximum flexibility reserve requirement is calculated. As part of phase one, SPP and stakeholders will define the:

- Detailed process by which reserve zones are initially determined and updated as needed.
- Methodology for determining zonal constraints for reserve zones.
- Compatible requirements, if necessary, to support existing flexibility reserve processes.

Once the anticipated Markets+ footprint is determined, SPP will utilize the process determined as part of phase one to identify any necessary reserve zones.

3.4.2 MARKET PROCESSES

3.4.2.1 MULTIDAY ADVISORY

The multiday forecast (MDFC) study is a non-binding, informational study that provides a commitment and pricing forecast based on the latest available forecast and commitment 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. Markets+ participants and SPP will finalize the specific study period and resulting granularity based on the specific resource mix and unique regional operating characteristics of the footprint during the next phase of design. SPP proposes the MDFC uses load and wind forecast data and expected resource availability and costs rather than attempt to model the behavior-based participation in the financial day-ahead market, but alternative inputs could be considered during phase one. SPP anticipates the specific details of the multiday forecast study to evolve over time.

The primary outputs of the MDFC are:

- Hourly pricing forecasts SPP will post publicly.
- Prospective, non-binding commitments SPP will communicate to corresponding market participants.
- Potential reliability issues SPP will communicate to the appropriate TOP/BA/RC.

SPP and the balancing authorities will coordinate any long-lead commitments that otherwise may not be committed through the DA market due to physical parameters or offered availability.

3.4.2.2 DAY-AHEAD MARKET AND PHYSICAL RESOURCE COMMITMENT

Like most RTO markets, SPP's existing market platform includes a financially binding day-ahead market, followed by a day-ahead RUC process that can secure incremental capacity to ensure the total physical supply committed meets the SPP operator's projected capacity needs during the operating day. While RUC is an important tool to ensure reliability, a day-ahead market optimization that regularly commits the majority of physical resources based on the behavior-based participation in the voluntary day-ahead market is likely to result in a less efficient overall dispatch and commitment solution relative to a market optimization that is designed to determine the most efficient use of all resources to meet all needs of the grid simultaneously. Regular reliance on the RUC process to fill capacity shortfalls resulting from the day-ahead market solution will produce less transparent pricing and increased uplifts because the cost of those additional resources are not reflected in market prices. As the grid mix evolves across the nation to include more variable resources and more uncertainty in real-time grid conditions, some market operators have observed a growing use of RUC (or other out-of-market actions), exacerbating these efficiency and pricing concerns and indicating a need to explore potential enhancements to the traditional day-ahead market.

For Markets+, SPP proposes to explore with stakeholders enhancements to its market design that would enable the day-ahead market solution to find the most efficient dispatch and commitment of the physical resources needed to meet the reliability needs of the market footprint and to produce transparent price signals reflecting the marginal cost of those resources.

The Markets+ market design sessions have narrowed the basic structure of the DA market to two possible implementations:

- Option one: A voluntary, financial market with financially binding day-ahead positions that include physical instructions for resources to start and stop. This is similar to the SPP regional transmission organization (RTO) Integrated Marketplace.

- Option two: A multistage process where a reliability-based, physical resource commitment occurs, followed by a purely financial and voluntary day-ahead market.

There are multiple nuances between the two structures, but the overarching difference is determining what drives the primary unit commitment for Markets+. Option one results in a market design where the primary unit commitment for Market+ is driven by the participant behavior in the voluntary, financial day-ahead market. With this option, the overall market design must incentivize participation to mirror the forecasted expectations of real time. When behavior deviates from what is expected in real time, the unit commitment may be suboptimal and result in incremental commitments in the subsequent reliability unit commitment processes (as described above). Option two results in a market design where the physical decision to commit is insulated from the voluntary, financial day-ahead market and is driven by the forecasted expectations for real time.

In phase one, SPP and stakeholders will determine if the expected benefits outweigh the complexity of implementing option two in place of the more industry-established option one. Early in phase one, SPP and stakeholders will determine which option best fits Markets+ considering downstream design impacts (e.g., convergence bidding, settlements, RUC, etc.), compatibility with the RTO West market design¹⁷ and the overall project scope and timeline.

SPP proposes during the next stage of detailed market design, participants assess external drivers in the Western Interconnection to determine what specific market timeline makes sense once the anticipated Markets+ footprint is understood. The duration between DA market close and posting of results is directly related to the complexity of design decisions finalized in the next phase of market design. Based on discussions to date, SPP anticipates three to four hours of processing time to complete and post the DA market solution for Markets+.

Consistent with SPP's current market in the east, Markets+ will allow participants to submit two sets of resource offer information: One for use in the voluntary, financial day-ahead market and the other for use in all other market processes.

3.4.2.3 RELIABILITY UNIT COMMITMENT

The RUC process begins shortly after posting of the day-ahead market results and will continuously validate the existing unit commitment decisions to ensure all Markets+ obligations are reliably and economically met based on the most recent forecast and operational information.

The RUC processes begin with hourly granularity assessments of the existing resource commitments covering the entire operating window that has been committed for in the day-

¹⁷ For example, if entities are interested eventually transitioning from Market+ to full RTO participation.

ahead process. Closer to real time, the RUC process will transition to a short term, more granular study (e.g., 15-minute granularity) assessing the next three to four hours.

SPP anticipates significant collaboration and coordination between the market operator and participating balancing authorities, especially approaching period of scarcity or strained system conditions.

During phase one, SPP and the appropriate stakeholder working groups will investigate the RUC processes and determine if any unexpected changes to transmission availability are necessary to support the RUC process.

3.4.2.4 REAL-TIME BALANCING MARKET

The RT market will occur near real time on a five-minute frequency, with a study interval of five minutes. This study provides a security-constrained energy dispatch and a co-optimized clearing of flexibility reserves and associated prices.

The RT market will initialize approximately five minutes before the target interval. The study is completed and results are approved and published approximately one minute before the start of the target interval.

3.4.3 RESOURCE PARTICIPATION MODELS

Markets+ includes multiple resource participation models, allowing participants to maximize the benefits of centralized unit commitment and dispatch while respecting the unique capabilities and operating characteristics of the asset. SPP proposes all resource registration and modeling occur at the point of interconnection to the transmission system and aggregation of multiple generating assets be limited to instances where resources share a common physical and electrically equivalent injection point to the transmission system. Limiting the market registration of generating resources to a single point of interconnection is important for congestion management. In addition to the standard resource participation model, SPP proposes the following additional participation models are included in Markets+.

3.4.3.1 MULTI-CONFIGURATION COMBINED CYCLE

A combined-cycle plant has the ability to generate power through more than one operating component. Typically, a combined-cycle plant consists of one or more gas-fired turbines and a steam turbine, both of which are capable of electricity generation. The gas turbine, in addition to producing electricity, exhausts waste heat, which can be captured to produce steam in the steam turbine allowing for additional electricity generation. Because combined-cycle plants vary in their design and number and type of components, they have multiple, distinct operating configurations, each with different levels of capacity, efficiency and physical operating characteristics.

To allow for selection of the most economic configuration in the centralized unit commitment and dispatch processes, participants may elect to register individual operating configurations. Participants can submit individual resource offers and physical characteristics for each configuration and information on how the combined-cycle plant transitions between registered configurations.

SPP proposes multi-configuration combined-cycle resource modeling be restricted to only combined-cycle resources at Markets+ launch.

3.4.3.2 MARKET STORAGE RESOURCE

An electric storage resource (ESR) is any resource capable of receiving electric energy and storing it for future injection of electric energy to the grid. To ensure these types of resources can participate in Markets+, SPP proposes a participation model that recognizes the physical and operating characteristics of ESRs be part of the Markets+ market design. To accommodate many types of ESR (e.g., batteries, pumped storage, flywheel, compressed air storage, etc.) the participation model will provide flexibility to the participant when submitting offer and operational information. SPP proposes the market participant manages the state of charge¹⁸ for the resource.

3.4.3.3 JOINT OPERATING UNIT

Joint operating units¹⁹ (JOU) are inherently complex to operate in an organized market. SPP proposes two options for JOU participation in Markets+ to provide flexibility to participants wishing to maximize the benefits of Markets+ optimization while still accounting for the unique operating conditions for a JOU.

In the first option, participants may elect to register their individual share as a separate resource. SPP would treat each individual resource separately for centralized unit commitment and dispatch decisions.

In the second option, participants may choose to register as a combined-interest resource. A combined-interest resource is registered as a single resource for market operation under a single market participant. Credits and charges for these resources are allocated using a percentage of submitted interest share in settlements.

3.4.3.4 DEMAND-RESPONSE RESOURCE

SPP proposes Markets+ market design include a participation model for demand response. The participation model will allow participants to offer a demand response permitted to participate in the wholesale energy market in a similar fashion to an injecting resource. In addition to the

¹⁸ State of charge is the amount of Energy stored expressed in MWhs.

¹⁹ A Joint Operating Unit is a resource that is owned by more than one entity or a resource for which multiple entities have contractual rights or financial obligations.

information required of an injecting resource, the participant will need to provide information related to the controllable load and/or behind-the-meter generation so SPP can properly account for the load reduction in market processes.

Consistent with other resource types, demand-response resources must meet the Markets+ minimum threshold requirement (e.g., 100kW) and may only aggregate under a single point of interconnection.

A controllable load not capable of responding to five-minute dispatch instructions but capable of hourly reduction of withdrawal of energy from the transmission grid will receive hourly dispatch instructions in the day-ahead market and real-time balancing market.

3.4.3.5 HYBRID STORAGE MARKET RESOURCE

As the proliferation of electricity storage and renewable generation continues in the west, SPP proposes Markets+ allow generating resources and ESR(s) located behind the same point of interconnection to the transmission system flexibility in asset registration. Participants may choose between registering the collection of resources in Markets+ as a single resource or individually. If the participant registers the resources as a single resource, the participant may choose to register the aggregation as a market storage resource, taking advantage of the participation model that recognizes the physical and operating characteristics of the ESR(s).

3.4.3.6 VARIABLE ENERGY RESOURCE

Variable energy resources²⁰ continue to make up a growing portion of the Western Interconnection resource mix. SPP proposes Markets+ include a participation model that maximizes the economic and societal benefits of this clean and cost-efficient generation type while maintaining reliability, except for instances where system reliability or economic efficiency are reduced.

For wind and solar-powered variable energy resources, SPP would produce and update hourly forecasts, providing a rolling 48-hour projection of wind and solar production potential. To produce an accurate and reliable forecast, SPP needs participants to provide additional geographical data, modeling and telemetry for wind and solar resources related to meteorological conditions.

For the financial day-ahead market, SPP proposes variable energy resources be able to participate similar to non-variable generation. For physical unit commitment processes, SPP will limit the maximum dispatch of wind and solar-powered variable energy resources to the lesser of the output forecast and the submitted maximum in the resource offer. For real-time market

²⁰ A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

operations, SPP proposes variable energy resources are expected to produce the maximum production potential unless SPP is actively dispatching the resource. SPP assumes a persistence forecast for variable energy resources except for instances when actively dispatching the resource in an upward or downward direction to properly account for this operating behavior in the real-time balancing market. SPP and stakeholders will identify valid exceptions for variable energy resources responding to dispatch in RTBM, such as a qualifying facility exercising its rights under PURPA²¹ to deliver its net output to its host utility.

SPP proposes any footprint-specific reliability constraints, such as maximum ramp rate, be determined in the next phase of detailed design when the Markets+ anticipated footprint is better understood.

3.4.3.7 EXTERNAL RESOURCES

Markets+ will include robust design features, allowing for transactions between external parties and participants in Markets+ as outlined in the Scheduling Activities and Bilateral Transactions section. SPP proposes no additional market design be included to accommodate external resources for Markets+. Entities with resources external to a participating balancing authority wishing to participate in Markets+ must **pseudo tie those resources** into a participating balancing authority, including all necessary transmission service reservations.

During phase one, SPP and stakeholders will determine if a more flexible external resource model should be included for Markets+ launch.

3.4.3.8 GROUPED HYDRO MODEL

Throughout the design session discussions, numerous stakeholders have expressed the need for market design features that account for the aggregate operation of multiple, individual hydro-powered generating resources on a common water system. During phase one, 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.

3.4.3.9 FUEL-LIMITED RESOURCES

Markets+ will provide participants with tools to manage the availability of fuel-limited resources. Resource offers will provide opportunities to communicate runtime constraints, such as maximum daily energy in MWh and maximum daily/weekly starts. During phase one, SPP and stakeholders will determine if additional resource constraints are necessary to accurately represent fuel-limited resources' ability to produce.

SPP anticipates the mitigation design will include opportunities for participants to represent the opportunity cost of fuel-limited resources in the cost-based, mitigated offers.

²¹ PURPA, Public Utility Regulatory Policies Act of 1978

3.4.3.10 LONG-LEAD RESOURCES

Long-lead resources are resources that require more notification time to start than is available when the day-ahead commitment processes complete. SPP does not propose Markets+ include commitment processes to commit long-lead resources. SPP expects long-lead resources would either self-commit into the market or would be committed by the appropriate reliability function (i.e., RC, BA, TOP) before the day-ahead process.

During phase one, SPP and stakeholders will determine if design changes could be pursued to allow for commitment of long-lead resources.

3.4.4 PRICE FORMATION

The primary goal for price formation is to determine accurate short-term prices that inform participants of the system's state and provide an incentive for supplying the various energy services necessary to reliably operate the transmission system. This is challenging as different participants may view accurate differently and argue they should be higher (the supply) or lower (the demand).

FERC has provided valuable guidance toward seeking price formation practices that will produce prices that meet a number of stated objectives²²:

- Maximize market surplus for consumer and suppliers.
- Provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment and maintain reliability.
- Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and operational constraints of reliably operating the system.
- Ensure that all suppliers have an opportunity to recover their costs.

Specific pricing elements SPP believes can support these objectives are described below.

²² In June 2014, the Commission initiated a proceeding, in Docket No. AD14-14- 000, to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs (price formation proceeding).

3.4.4.1 LOCATIONAL MARGINAL PRICING

SPP uses a co-optimized, security-constrained economic dispatch (SCED) model to compute LMPs for energy at individual pricing nodes²³. The LMP at a pricing node represents the cost of delivering an incremental MW of energy at that specific location while satisfying all operational constraints.

LMP components at pricing node i are calculated based upon the following formulas:

$$\text{LMP}_i = \text{MEC} + \text{MLC}_i + \text{MCC}_i$$

Where:

- MEC is the component of LMP_i representing the marginal cost of energy.
- MLC_i is the component of LMP_i representing the marginal cost of losses at PNode i relative to the reference bus.
- MCC_i is the component of LMP_i , representing the marginal cost of congestion at ENode i relative to the reference bus.
- The reference bus represents the network distributed load bus.

Calculating the appropriate LMP relies on energy offers and transmission system characteristics.

²³ Pricing nodes represent a single node in the commercial model that has a one-to-one relationship to a point of interconnection to the transmission system where electrical and equipment and components are connected.

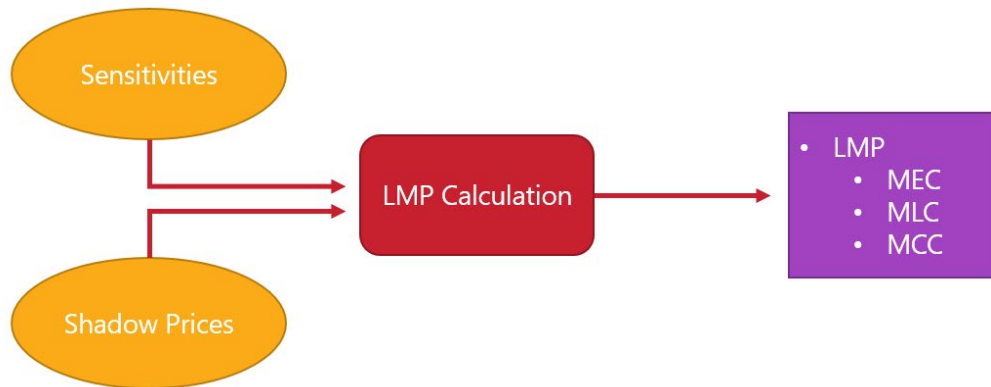


EXHIBIT 4 1: LMP CALCULATION OVERVIEW

3.4.4.2 SIMULTANEOUS CO-OPTIMIZATION OF MARKET PRODUCTS

Markets+ centralized unit commitment and dispatch processes will incorporate co-optimization. Co-optimization is a widely used and accepted methodology that allows the optimization algorithm to make the best decision, where it may not be apparent, when assessing individual products for clearing. Co-optimization logic assesses energy and reserve products simultaneously to produce the least-cost solution while maximizing individual participant benefits and accurately reflecting the demand for each product in pricing. Lost opportunity costs are embedded in the co-optimization algorithm and ensure product pricing accounts for any resource's lost opportunity to sell energy for a given product to clear a different one. This is essential to ensure resources are indifferent to the product cleared and represent the lost net revenue of foregoing the clearing of another product. Energy and reserve products include lost opportunity costs in the clearing and pricing algorithm.

3.4.4.3 FAST-START RESOURCE PRICING

Nearly all organized markets in the United States include fast-start resource pricing logic to better reflect the marginal cost of meeting load in real time. Absent such logic, fast-start resources (typically gas-peaking units) that may be relatively inflexible and deployed at a fixed level of output (e.g., 50 MW) can often be prevented from setting the market clearing price, even when the resource is being committed on short notice to meet load in real time. Even if a fast-start resource is technically capable of setting price, its near-term commitment costs are typically not reflected in its energy offer curve. Because of these characteristics and as explained by FERC, "a lack of fast-start pricing practices may result in market prices that fail to accurately reflect the marginal cost of serving load."

SPP proposes to include fast-start resource pricing logic for Markets+ in a manner that is generally consistent with FERC's directives for applying fast-start resource pricing in SPP, NYISO and PJM, subject to stakeholder dialogue to develop the final detailed approach. Among other elements, SPP proposes fast-start resource pricing logic for Markets+ include two fundamental elements by ensuring the software will:

- Relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero for the purpose of calculating prices.
- Incorporate commitment costs, i.e., startup and no-load costs, of fast-start resources in energy and flexibility reserve prices.

Additional Background

Like other organized energy markets, Markets+ will allow 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. Historically in organized energy markets, all three parts of the resource offer are included in the commitment decision, while the centralized dispatch only considers the energy offer curve. Most organized markets have evolved to include the full three-part resource offer in the dispatch decision in specific conditions.

In December 2016, FERC issued a notice of proposed rulemaking (NOPR) in Docket RM17-3 to require each RTO/ISO to adopt market rules meeting certain requirements for pricing fast-start resources²⁴. FERC determined under certain conditions, the decision to commit fast-start resources was part of the dispatch decision, and commitment costs should influence price formation to “recognize that fast-start resources are . . . the marginal resource used to meet the next increment of energy or operating reserves demand.” On June 12, 2019, SPP received FERC Order EL18-35 mandating fast-start pricing for its RTO market.

For the centralized unit dispatch pricing and quantity clearing, Markets+ will include similar price formation logic to account for fast-start resources’²⁵ ability to quickly respond to needs on the transmission system as is used in SPP’s RTO market.

Under certain conditions, e.g., starting a resource to respond to an unexpected loss in variable energy resource output, the decision to commit a fast-start resource occurs near real time, effectively making the commitment decision part of the dispatch decision. In these situations, the cost to start the resource and the cost to maintain minimum output (i.e., commitment costs) should be included in price formation.

²⁴ Fast-start pricing in market operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,213 (2016).

²⁵ A specific definition of a fast-start resource has yet to be determined for Markets+. Most markets define a fast-start resource as a resource capable of coming online from an offline state and being dispatchable between 10 and 60 minutes of notification from the market operator and is capable of shutting down within one hour of starting.

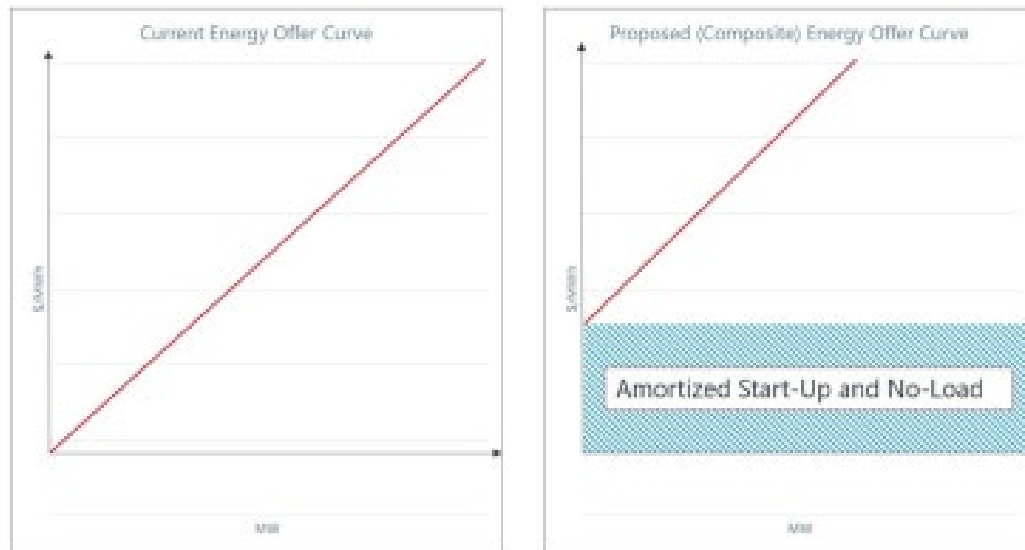


Exhibit 4 2: Energy Offer Curve versus Composite Energy Offer Curve

The commitment of fast-start resources approaching real-time results in additional complications for price formation because the nature of resource commitments will occasionally limit eligibility to set price, primarily due to the physical operating limits of the resource. For example, a fast-start resource is the marginal decision to resolve a transmission constraint on the system and is committed close to real time, fully resolving the constraint at its operating minimum. To ensure fast-start resources are eligible to set price for the operating condition they are committed to resolve, SPP proposes the operating characteristics preventing eligibility to set price be relaxed for determining price. To ensure a reliable and feasible physical dispatch, SPP will enforce the operating constraints when determining the physical dispatch, necessitating a separate physical dispatch and separate financial price component of the centralized unit dispatch processes.

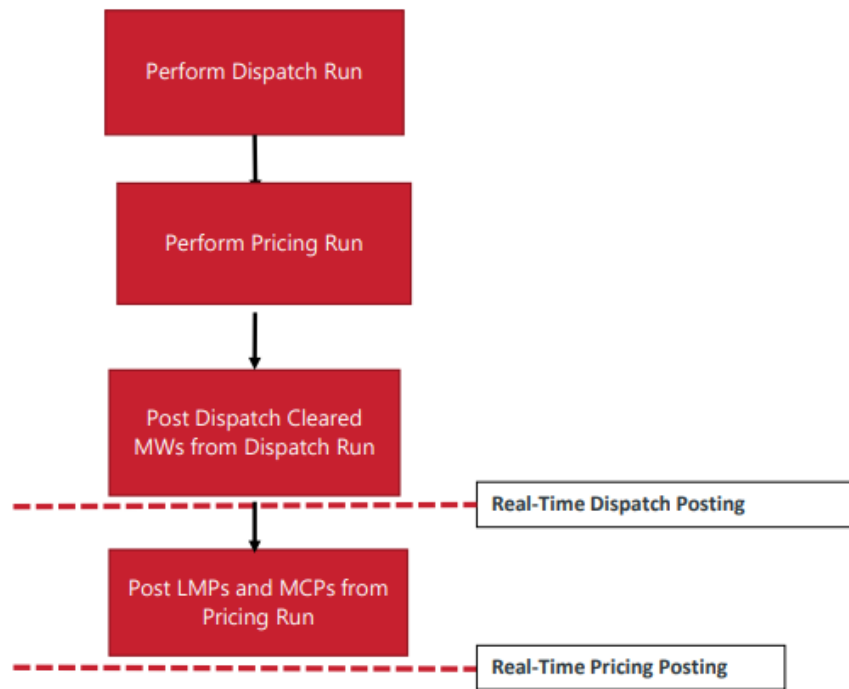


EXHIBIT 5: POTENTIAL REAL-TIME DISPATCH AND PRICING PROCESS

3.4.4.4 SCARCITY PRICING AND STRESSED SYSTEM CONDITIONS

To achieve the goals for price formation discussed above, it is important to have transparent and informative pricing during shortage or scarcity conditions. It is relatively easy to determine the proper price in a commodity market when demand is elastic and the desired amount changes with price. However, demand is currently highly inelastic in organized energy markets. The short-term price signal for Markets+ must reflect the current conditions, including scarce conditions, while properly compensating resources for the essential reliability services they are providing to the system. To properly determine prices, SPP proposes approximations in demand behavior be made in shortage conditions.

When the system cannot meet the reserve product requirement, prices are impacted by administrative pricing (e.g., demand curves)²⁶. Demand curves can be a single value, stepped or sloped based on the level of shortage. SPP proposes the appropriate demand curves for Markets+ be derived based on the cost of the next action to resolve the shortage as a starting point during the next phase of detailed market design. SPP proposes required “check and

²⁶ Demand curves are a series of quantity/price points used to set prices when there is a shortage of energy or reserve supply.

adjust” processes be established in the Markets+ tariff, requiring annual review of the scarcity pricing model performance.

3.4.5 CENTRALIZED UNIT COMMITMENT

Markets+ has two primary and complementary unit commitment objectives. First, the centralized unit commitment processes must maintain reliable operation of the bulk electric system by ensuring participating balancing authorities remain individually sufficient and the collective set of resources committed for a given time period is deliverable to load and export obligations. Second, the centralized unit commitment process should minimize total cost to produce. To have the fullest set of possible resources for commitment, market design must maximize the participation of resources’ load and interchange in the day-ahead horizon when the largest set of resources is available for unit commitment.

The primary unit commitment for Markets+ will occur in the day-ahead horizon, followed by numerous RUC studies that continuously refine and add to the commitments based on unforeseen changing conditions.

3.4.5.1 MULTIPLE BALANCING AUTHORITIES

Unlike other organized wholesale energy markets, Markets+ will not include consolidation of balancing authorities into a single, regional balancing authority. As such, the individual balancing authorities must remain individually sufficient before and throughout the operating horizon. The transmission capability made available for centralized unit commitment and dispatch will be a key input that constrains the centralized unit commitment. This will result in a Markets+ resource plan that maximizes the benefit and maintains the individual sufficiency of participating BAs. Phase one discussions will determine the specific details of how this constraint will be modeled in coordination with the participating balancing authorities.

3.4.5.2 UNIT COMMITMENT KEY INPUTS

To ensure a reliable and economically optimal unit commitment solution, several key inputs are required for all unit commitment processes in Markets+²⁷. These inputs are necessary for the market operator to accurately forecast the total and individual net obligations and system conditions.

Submitted and updated as needed by market participants:

- Resource physical capabilities

²⁷ SPP anticipates coordination on inputs with participating balancing authorities to validate reliability and feasibility. The specific details will be determined in the next phase of detailed market design.

- o Operating limits, ramp rates, dispatchability, etc.
- Resource economic participation
 - o Availability for economic commit and/or dispatch, startup cost, no-load cost, energy offer curve, etc.
- Outage information (resource and transmission)

Generated by SPP as the market operator:

- Load forecast (hourly for next seven days, 15-minute for next three hours)
- Wind/solar resource forecast (hourly for next seven days, 15-minutes for next three hours)

It is to be determined which entity is responsible for submitting:

- Transfer capability for shifting commitment obligation between participating BAs
- Forward capacity obligations between participating BAs
- Data necessary to support centralized greenhouse gas accounting and pricing in the centralized unit commitment
- Service flow constraint limits

3.4.6 CENTRALIZED UNIT DISPATCH

The goal of centralized unit dispatch is to optimize the dispatchable resource mix for the Markets+ footprint to minimize costs to meet the collective obligation of all participants while respecting the various operating constraints necessary to ensure reliability and equitable operation.

The centralized unit dispatch determines the nodal energy prices and the product reserve prices for each interval.

As the market operator, SPP will communicate energy dispatch instructions to dispatchable resources for every five-minute operating interval in the real-time market. SPP will not issue or include deployment of regulation or contingency reserves. SPP-provided energy dispatch instruction and any instruction from the balancing authority and reliability coordinator should be combined to determine the desired output for the resource.

As part of the design phase, SPP will work with Markets+ participants to determine the appropriate interaction between the market and the balancing authority's requirement to balance and remain sufficient.

3.4.7 PHYSICAL SUFFICIENCY IN MARKETS+

Physical sufficiency before and throughout the operating horizon is a critical component of the Markets+ market design and can be broken down into two phases: Resource adequacy or capacity adequacy and resource sufficiency or energy sufficiency.

3.4.7.1 MARKETS+ RESOURCE ADEQUACY REQUIREMENT

Resource adequacy (RA) programs ensure sufficient installed capacity to maintain reliability while allowing entities to benefit from the diversity of a broader regional footprint through lower individual capacity requirements. For the same reasons that most RTO/ISO markets have a common RA requirement, SPP believes a common RA requirement for Markets+ is an appropriate and necessary prerequisite to market participation. This will enhance reliability by verifying each load-responsible entity contributes its individual share of the overall capacity needs of the market footprint.

These objectives can be achieved by requiring all load-responsible entities participating in Markets+ participate in a common, FERC-approved resource adequacy program. Significant momentum and progress are being made in the Western Resource Adequacy Program (WRAP), and SPP proposes this program be used as the common, FERC-approved resource adequacy program for Markets+, provided FERC approves the proposed model without material changes. Design elements that may be necessary to support interoperability between the WRAP and Markets+ will be incorporated in phase one.

3.4.7.2 ENSURING RESOURCE SUFFICIENCY IN MARKETS+ THROUGH A MUST-OFFER QUANTITY

Resource sufficiency or energy sufficiency will be a key design feature of Markets+. To ensure reliable operation of the participating balancing authorities in Markets+, there must be extremely high confidence in the centralized unit commitment and dispatch of participating resources. The primary unit commitment for Markets+ will occur in the day-ahead horizon. There must be sufficient participating physical and deliverable resource capacity to meet the forecasted needs for that commitment to be reliable.

To help meet this objective, organized energy markets typically have minimum participation requirements to ensure the forward and spot-clearing processes have sufficient supply available to meet the anticipated demand. SPP proposes a must-offer quantity for Markets+ would complement the Markets+ RA requirement by ensuring each entity offers enough total supply in the day-ahead market to, at a minimum, meet its own needs (i.e., load, committed interchange, reserves and uncertainty), increased by any potential holdback obligation quantity to others or decreased by any potential holdback request from others, as calculated by WRAP. This approach ensures WRAP members can realize the benefits of WRAP's calculated diversity benefit by automatically updating each WRAP member's must-offer quantity based on the WRAP holdback calculations.

The combination of a forward Markets+ RA requirement (based on the WRAP forward showing) and a day-ahead must-offer quantity (base on the WRAP operational program) negates the need for additional daily or hourly resource sufficiency tests. This approach – a common RA requirement coupled with a dynamic must-offer quantity obligation – better ensures sufficient aggregate supply and more equitable outcomes than alternative approaches that rely on reconciling different resource adequacy approaches through an operational resource sufficiency framework.

As part of the next phase of detailed market design, SPP proposes a joint task force be created to facilitate joint meetings to discuss these concepts and to determine the necessary coordination needed between Markets+ and WRAP.

SPP and participants will work to determine the monitoring and settlement impact of the physical sufficiency component in the next stage of detailed market design.

3.4.7.3 COORDINATION WITH OTHER ENTITIES IN WRAP

Resource adequacy and capacity sufficiency occur over much longer planning horizons than the market processes contemplated for Markets+. Because of this, SPP does not propose that Markets+ create or establish a comprehensive resource adequacy program, but requires participants comply with a common, FERC-approved program. Given the momentum, interest and recently filing at FERC, SPP proposes the, Western Power Pool's Western Resource Adequacy Program (WRAP) be the common RA program used by Markets+ participants and will support WRAP obligations to other areas of the west that are not participating in Markets+. Early in phase one, SPP proposes a joint task force be created to facilitate joint meetings to discuss the interoperability and necessary coordination needed between Markets+ and WRAP.

3.4.8 CONGESTION RENT ALLOCATION

After the day-ahead market clears, all imports, exports, generators and load will settle at a locational marginal price (LMP). The marginal congestion component (MCC) of the LMP at each settlement location is multiplied by the cleared MW quantity at that same location and aggregated across the market footprint each hour. The resulting surplus revenue collected by the market operator is known as congestion rent and must be allocated back to market participants with firm transmission rights in a way that supports the incentives for customers to continue to invest in long-term transmission service.

SPP currently assumes the proposed congestion rent allocation approach for Markets+ includes the following elements. Further development of the eligibility requirements will be discussed under Other Considerations and included in the next phase of the initiative:

- Congestion rent allocation will be based on OATT transmission service reservations (TSRs), not schedules.

- The congestion rent approach will allocate congestion rents to long-term firm network and point-to-point (PTP) service rights.
- Congestion rent allocation will be based on a mapping of each eligible TSR to a source/sink pair, with the maximum congestion rent allocation reflecting the MW quantity of the applicable TSR multiplied by the differential between the MCC at the applicable source and sink locations.
- Congestion rent allocation will be based on prevailing flows only (meaning that congestion that occurs in the opposite direction of a transmission reservation's source/sink combination will not result in a payment obligation by that rights holder).
- The total congestion rent allocated to transmission customers will be equal to the total congestion rent collected by the market operator for each hour. This ensures the market operator is revenue neutral and uplift charges or other true-ups are not required. This approach may result in congestion rent allocations that are less than 100% of the nominal transmission reservation quantity (e.g., reflecting derates).

3.4.8.1 NETWORK TRANSMISSION RIGHTS

Unlike PTP transmission service that provides a defined MW capacity for the entire period of the reservation, network transmission rights are limited to the network customer's actual load each hour. A network customer may have more supply capability from designated network resources (DNRs) than it has load at a particular point in time, and a methodology must be developed to determine the appropriate quantity and source/sink pair(s) for purposes of allocating congestion rent to network customers.

To achieve this outcome, SPP proposes a congestion rent allocation cap be calculated using the maximum quantity of network transmission rights set equal to a three-year average of the customer's network load multiplied by 103%. The details for how the 103% is applied in a given time period will be determined in phase one.

This approach ensures the entities receive congestion rent on the appropriate paths (from available network resource to network load) and for the appropriate quantity (total yearly load). This approach recognizes network load is charge based upon the coincident peak load for that year. This approach provides network customers with an economic value when delivering their DNRs on their network rights to their load, while also allowing the market to seek more economic supply when available (making the customer better off).

3.4.8.2 POINT-TO-POINT RIGHTS

For PTP rights, the congestion rent allocation cap will be based on the MW capacity of each eligible transmission reservation.

3.4.8.3 REVENUE NEUTRALITY

To ensure revenue neutrality, the total congestion rents allocated to transmission customers must be equal to the total congestion rent collected by the market operator.

Conceptually, revenue neutrality is assured by converting congestion rent allocations to a ratio multiplied by the total congestion rents collected by the market operator:

$$\text{Congestion Rent Ratio for TSR A} = \frac{(MW \text{ TSR "A"} * (\text{Source MCC} - \text{Sink MCC}))}{\sum \text{All TSRs} (MW * (\text{Source MCC} - \text{Sink MCC}))}$$

Other considerations: In the first phase of the market design, Markets+ stakeholders will need to consider and approve these design elements:

- SPP proposes to investigate defining congestion rent zones to enable a more granular approach to the allocation process to mitigate concerns about the potential dilution of allocations to transmission service rights holders. For example, if a derate is implemented on an element in the Pacific Northwest (PNW) system, zones could be used to support limiting the impacts of the derate in the congestion rent allocations to the PNW zone, instead of allocating the impacts across the entire market footprint. The number of zones and the methodology of the approach should be explored in more detail during Phase 1. Markets+ will only have one Reference Bus to calculate the MCC. The MCC of each Settlement Location could be affected depending on the relative size of the shift factor and the derate of the constraint. Therefore, the zonal approach may not be sufficient by itself. Another way to mitigate the impact of localized derates on the system, could be to have the TSP limit the quantity of MWs eligible for use in congestion rent allocation on a TSR before the close of the DAMKT. SPP supports exploring both approaches during Phase 1 and developing a solution address concerns raised by stakeholders over the past several months.
- Currently, only firm priority seven TSRs will be considered in the congestion rent allocation. Conditional firm TSRs under defined circumstances will need to be examined.
- Is the congestion rent allocation cap for network customers (103% of the customer's network load) calculated yearly, monthly, daily or hourly?
- Should the network customer supply a resource plan in advance of the day-ahead market that identifies which DNRs it would use to meet its own load, absent a market optimization? To ensure the resource plan is consistent with the resources the network customer would have used to meet its load, SPP could simply select the resources offered into the day-ahead market, starting with the lowest-cost resource until all load is satisfied.

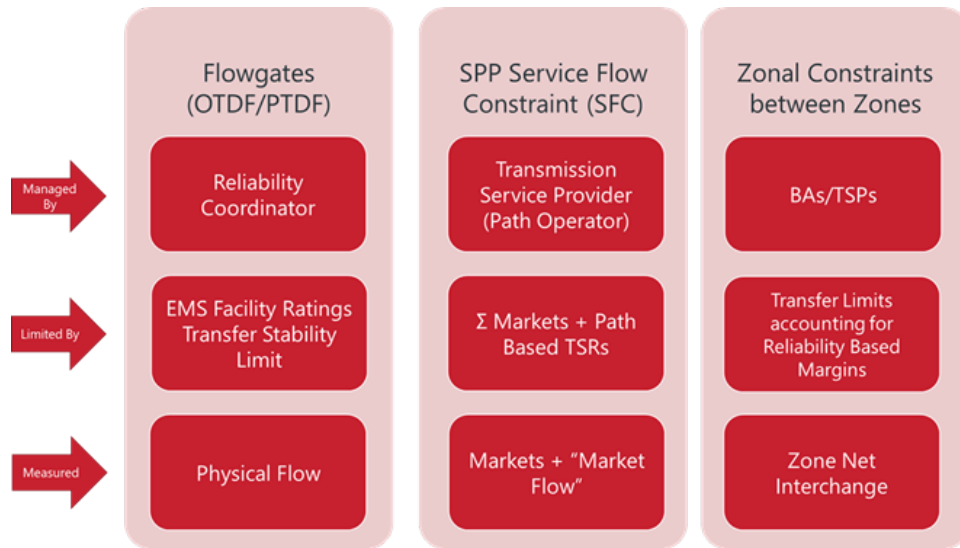
- Should congestion rent be allocated on a tiered approach? An example of this would be to allocate the congestion rents up to the full value of priority seven TSRs followed by any additional congestion rent being allocated to priority six TSRs.
- During phase one, the details for how transmission customers and TSPs will confirm and communicate to SPP the TSRs, including source, sink, MW limit and time period eligible for the congestion rent allocation.
- The congestion rent allocation is specific to the day-ahead market. Firm TSRs will not be used in order to obtain real-time congestion rents.

3.4.9 FLOW-BASED MARKET OPERATIONS AND PHYSICAL DELIVERABILITY

As a market operator, SPP intends to operate the bulk electric system in close coordination with the TSP, TOPs and the reliability coordinator to the system operating limits (SOLs) and interconnection reliability operating limits (IROLs), in addition to any transmission constraints associated with transmission scheduling limitations. SPP systems will calculate the impact of the market dispatch serving load within the Markets+ footprint to ensure a reliable operation when performing an economic commitment and dispatch of the participating resources. Any redispatch obligation assigned to the Markets+ TOP or reliability coordinator will be reflected in an effective limit activated in the market on the associated modeled transmission constraints. These limits are known as flow gates.

The proposed approach will ensure maximization of the available transmission system while maintaining reliability and respecting the market participants' rights on the transmission system not included in the Markets+ footprint.

Markets+ will respect capacity rights not associated with a Markets+ participant on transmission scheduling. The Western Electricity Coordinating Council (WECC) path or other transmission service-limiting elements will be modeled as service flow constraints (SFCs). The transmission service providers will provide all transmission services, used and unused, to the market operator via an ICCP link. The market operator will efficiently utilize transmission by continuously calculating and updating the service flow constraints of all Markets+ participants' transmission paths.



The following summarizes the expected interaction between Markets+ and service flow constraints.

- Markets+ does not change the scheduling and transmission service request methodology as implemented by each TSP.
- Transmission service sold on a path methodology or flow gate methodology basis will continue to be evaluated and sold as is and in accordance with the TSP's methodology.
- SPP will evaluate the impact of any transmission service, tag or schedule on any congestion on flow-based basis. This is done to assess congestion rents.
- Curtailment of any transmission service will continue to be the responsibility of the TSP, balancing authority and reliability coordinator.

3.4.10 VIRTUALS OFFERS AND BIDS

Convergence between the forward and spot market for energy in Markets+ is an important measure of market health for two critical reasons.

First, the health of an open market can generally be measured by convergence. In an open market, intelligent and responsible buyers do not want to pay more for a product than it will be worth. Likewise, intelligent and responsible sellers do not want to be paid less for a product than it will be worth.

Second, excessive and systemic divergence between markets leads to arbitrage scenarios where profits are achieved with little or no risk, while the associated losses occur with little or no means of avoidance. The behaviors and methods of participation to reap the profits rarely provide benefit to the overall market since they do not contribute toward convergence. In an energy

market, these types of divergences are generally a flaw in the model, a gap in the market design or misadministration of the market.

The majority of Markets+ resource commitment decisions will occur in the day-ahead horizon. SPP proposes the day-ahead market is not the originator of those decisions, but it is critically important the voluntary, financial market converge with the expected needs of real-time for those forward prices to properly inform and incentivize performance in the market.

Convergence bidding²⁸ is a market design instrument intended to open and converge the market. Since asset ownership is not required for convergence bidding, any entity with sufficient credit would be able to participate in the market, increasing liquidity beyond what would likely be experienced in a market solely consisting of asset-owning participants. Convergence bidding provides a mechanism for participants to push the markets toward convergence when behavior in the day-ahead market leads to divergence.

SPP continues to work with Markets+ stakeholders to determine if convergence bidding should be part of the initial Markets+ design. Stakeholders prefer to delay convergence bidding for a period of time, e.g., one to two years after Markets+ launch, to allow the market to mature and allow participants to gain comfort and proficiency in market participation.

During phase one, SPP will perform studies and analysis to identify unintended consequences of delaying convergence bidding and how convergence bidding impacts Markets+ price formation and physical unit commitment.

SPP proposes Markets+ incorporates convergence bidding in the overall market design in parallel to determining the need for any necessary delay to make convergence bidding effective.

3.4.11 MARGINAL LOSSES

As part of the co-optimization of dispatch and unit commitment, SPP's market will assess the deliverability of energy to load and the associated transmission system losses to optimize energy costs. Losses are estimated and reflected as a cost in LMP as the marginal losses component. The losses are calculated for every node and aggregated to the appropriate settlement hierarchy. SPP proposes a marginal losses concept instead of the average loss calculation concept because of the enhanced cost optimization and support from FERC. The average loss calculation concept would not be included in the LMP because of its uniform distribution of the total system losses.

Losses will be included in SPP's footprint load forecast and the market's unit commitment and dispatch balance, with estimated transmission losses included. In a marginal losses concept,

²⁸ Virtual offers and bids in SPP's RTO organized market, The Integrated Marketplace.

SPP's market will assess how much an incremental MW injection at every node increases or decreases the transmission system losses in the footprint.

3.5.0 GREENHOUSE GAS (GHG) ZONES AND REPORTING

SPP proposes two constructs to manage different levels of requirements for greenhouse gas (GHG) programs and initiatives. For states or zones with carbon pricing programs, SPP, in coordination with its stakeholders and participants, may consider this for a GHG pricing zone construct in its market design. For states or zones with carbon reduction targets, but without a carbon pricing program, SPP proposes a separate constructs, GHG non-pricing zone, focusing on facilitation of the accounting, tracking and reporting data required to monitor emissions consumption by state, zone or region.

SPP will establish stakeholder processes, working groups and task forces to focus on the GHG design. The coordination will include and be open to feedback from state departments or agencies responsible for state GHG programs.

3.5.1 GHG PRICING ZONE

SPP's market design will include the cost to serve load in states with greenhouse gas (GHG) programs in its market optimization and will work with participants to implement the necessary tracking and reporting associated with MWs serving load in the GHG state(s). The current market design proposal utilizes a zonal approach, where the zone represents the state(s) with a program requiring collecting and paying GHG costs associated with various resources' carbon emission attributes. The market optimization will consider the submitted energy offer for all resources in addition to the emission cost of the generation (GHG cost), which would be submitted to SPP when making the optimization decision to serve load in a GHG pricing zone. The proposed design allows for the ability of any offer resource in Markets+ to participate in serving load in a GHG pricing zone. A different classification of resources is needed to ensure the appropriate GHG emission rate is assigned on a resource level for internal GHG generation, imports associated with specified resources and from the rest of the fleet on an aggregate basis. The design supports the classification of three distinct categories of resources serving the load in a GHG pricing zone: Zone-internal generation, specified-source imports and unspecified-source imports.

GHG costs will be captured separately from the LMP for resources imported into the GHG pricing zone and are settled with the zone's load and generation produced or imported into the zone. The MWs assigned to the zone, all energy produced within the zone and energy imported into the GHG pricing zone are subject to the GHG costs, which reflect the calculated price produced by the optimization solution reflecting the marginal cost to serve load inside the zone.

Through the stakeholder process, SPP will work with the participants to ensure the GHG design:

- Minimizes total production costs with GHG costs considered.

- Provides a framework for any capacity to be dispatched to the zone.
- Properly accounts for specified and unspecified MWs serving the zone.
- Implements a solution that meets the intent of GHG policies.
- Ensures that GHG costs associated with imports into the GHG zone only apply to load in that zone.

3.5.1.1 MW REDESIGNATION CONCERNS

Resources external to a GHG pricing zone associated with specified-source imports into the zone may be economical and may produce the same energy amount to serve load in the Markets+ footprint regardless of the GHG pricing zone and its costs. In this case, the incremental energy incentivized by the GHG program may be considered zero. If energy is assigned to a zone solely based on the existence of a specified-source import designation, it could be considered by the GHG program as a re-designation of energy carbon-emitting resources may displace. In this case, the GHG program objectives would not have accomplished its objective of incentivizing reduction in generation emissions.

SPP will continue to work with stakeholders to evaluate several proposals to minimize MW re-designation of energy imported to a GHG pricing zone, including modeling a two-pass solution to establish a baseline for measuring incremental energy incentivized by the zone. Detailed design of this solution will be discussed through the stakeholder process, including the coordination of this market feature with other market design elements such as fast-start pricing.

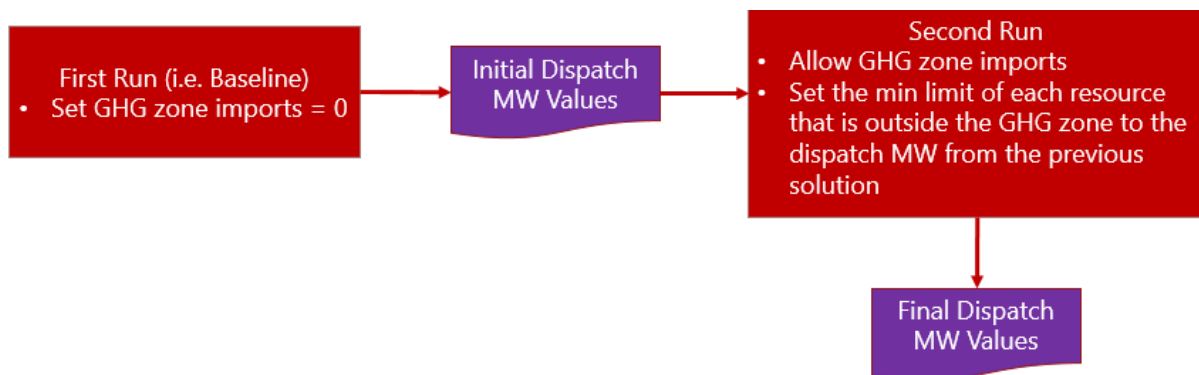


Exhibit 5: GHG Process

3.5.1.2 GHG PRICING ZONE TRACKING AND REPORTING

For states with programs requiring the GHG market design component, MWs assignment by resources for internal GHG zones and specified-source imports is necessary for settlements. SPP will not track the MW source on a resource-specific basis for unspecified-source imports.

3.5.2 GHG NON-PRICING ZONE

As the market operator, SPP will support tracking and reporting of the production of generation by fuel type in its footprint for GHG non-pricing zones. For any state or zone seeking to impact dispatch and commitment for their area based on CO₂ emissions, rate details may be needed from state agencies or other legislative or regulatory mandates to support an application to FERC for the zone being considered a GHG pricing zone.

3.5.2.1 GHG NON-PRICING ZONE TRACKING AND REPORTING

Through the appropriate stakeholder processes and forums, appropriate metrics, format and data requirements should be established to facilitate any tracking and reporting efforts the industry needs to meet state reporting mandates.

SPP and its stakeholders will determine the appropriate entities to receive the necessary data from the market operator to establish and implement business rules needed to associate generation production with load consumption by state or region. These rules should be established and implemented outside the market operator's purview.

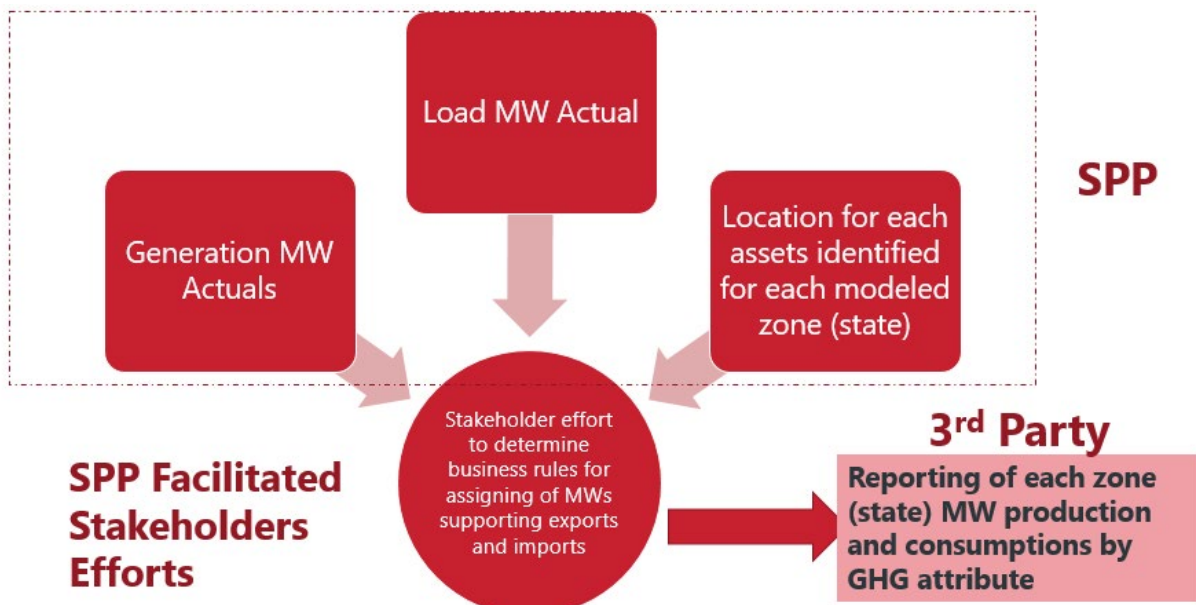


Exhibit 6: Tracking and Reporting Development

4.0 MARKETS+ COMPATIBILITY WITH EXISTING CONSTRUCTS

4.1 SCHEDULING ACTIVITIES AND BILATERAL TRANSACTIONS

Interchange schedules affecting Markets+ are schedules that source external, sink internal or have a source and sink external with a POR/POD with at least one participating balancing authority. Interchange schedules entering or exiting the Markets+ footprint must have transmission service reservations across the TSPs in Markets+, as necessary, to inject or withdraw energy with non-market areas. As part of the centralized unit commitment and dispatch, Markets+ will utilize all available transmission to maximize the economic value of pooling generation to meet the total Markets+ NSI requirement. Markets+ will constrain market flow within system operating limits as part of the security-constrained economic dispatch. In addition to constraining the economic dispatch based on the physical capabilities of the transmission system, SPP proposes Markets+ include constraints to limit market dispatch to reduce market flow on individual elements or sets of elements to respect external, non-participating entities' transmission rights.

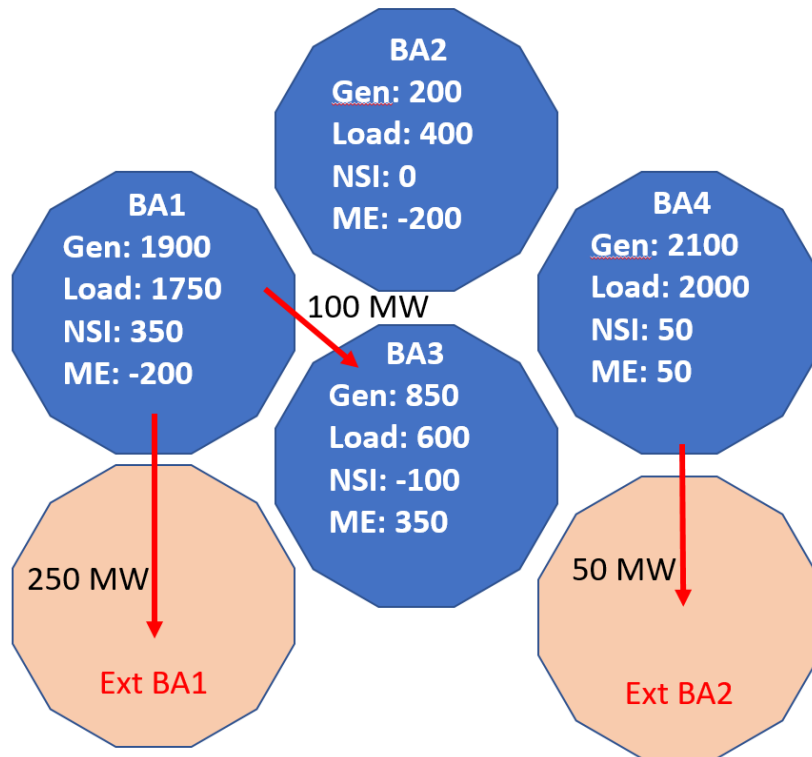


EXHIBIT 7: MARKETS+ SCHEDULING EXAMPLE

To illustrate the concept of Markets+ scheduling, consider the example above.

BA1 – BA3 has an intra-market schedule of 100 MW

BA1 – Ext BA1 has a Markets+ schedule of 250 MW

BA4 – Ext BA2 has a Markets+ schedule of 50 MW

The total obligation to the market is the sum of the load and NSI for participating balancing authorities.

$$\text{Market Obligation} = 1750 + 350 + 400 + 600 - 100 + 2000 + 50$$

$$\text{Market Obligation} = 5,050 \text{ MW}$$

The economic dispatch in this example is 1,900 MW for BA1, 200 MW for BA2, 850 MW for BA3 and 2,100 MW for BA4. To account for the resulting market flows for balancing authorities, SPP proposes participating balancing authorities create dynamic schedules. Markets+ will provide a dynamic schedule adjustment representing the total import/export from market flows to provide the transparency necessary to support reliability for the Western Interconnection.

For BA1:

$$\text{Markets} + \text{Flow} = \text{Dispatch} - (\text{Load} + \text{NSI})$$

$$\text{Markets} + \text{Flow} = 1900 - (1750 + 350)$$

$$\text{Market Flows} + = -200 \text{ MW}$$

Market participants may utilize e-tags to document a bilateral agreement to establish a generation-to-load relationship between contractual entities. The billing arrangements are specific and confidential to the entities on the tag. SPP proposes the PSE for the e-tag is responsible for the transaction billing outside of the market, and Markets+ does not serve as a clearinghouse for contractual agreements outside the market. Markets+ settlements could support financial schedule settlements, allowing for transfer of ownership of energy at a settlement location. SPP proposes e-tags serve as the data artifact, demonstrating the generation-to-load relationship and underlying transmission service supporting the deliverability across the transmission system.

Market participants may utilize e-tags to document transactions with no contract and no specified generator or load. These e-tags are intended to buy from one market and supply to another to take advantage of pricing differentials across an interface.

Markets+ uses market dispatch to settle e-tags that enter, leave or wheel through the SPP Markets+ footprint. This Markets+ settlement methodology is the same for all e-tag transactions for imports, exports or wheels regardless of whether the market participant has a contractual obligation for the e-tag document outside the market.

All Markets+ schedules will be settled at the LMP of the interface specified on the tag. The interface is the point at which the transaction is injected or withdrawn from the Markets+ boundary. The Markets+ settlement locations representing the market's location supporting the transaction is responsible for the settlement of the exports, import or wheel in the market. Transmission service must be procured to support schedules from the source to the sink outside of the Markets+ process.

4.2 TYPES OF MARKET SCHEDULES

SPP proposes interchange schedules (for normal and dynamic tag types) identified as part of schedule creation to distinguish which interchange schedules are intended for the day-ahead market and which are only intended for real-time. SPP proposes all markets schedules require valid TSRs before consideration.

Participants will submit any known interchange to SPP through the day-ahead or real-time market processes. Market schedules require the following information:

- Market date
- Bids and offers for exports and imports
- Market type designation – fixed, dispatchable
- Market transaction designation – real time or day ahead
- MW profile

PSEs cannot create, adjust, correct or extend day-ahead schedules while the day-ahead market processes. Any adjustment to the tag after-market clearing will be settled as a deviation from the day-ahead market in settlements.

There are two marketplace transaction types supported for interchange transactions: Fixed and dispatchable.

4.2.1 FIXED INTERCHANGE SCHEDULES

Fixed interchange transactions are physical transactions that bring energy into and/or out of the Markets+ footprint. Energy prices are settled at the LMP at the applicable external interface settlement location. Any entity who submits this type of transaction in Markets+ is the price taker for that energy.

SPP proposes fixed interchange schedules are supported in both the day-ahead market and in the real-time market.

4.2.2 DISPATCHABLE INTERCHANGE SCHEDULES

Dispatchable interchange schedules are physical transactions that bring energy into and/or out of the Markets+ footprint and specify a bid or offer (MWh). SPP proposes these schedules are supported in the day-ahead market only.

A dispatchable offer specifies both a MW amount and a minimum price the customer must pay if the transaction clears the day-ahead market, effectively representing a proxy price-sensitive generator or load at the Markets+ interface.

If the dispatchable interchange schedule is cleared in the day-ahead market, it continues into the real-time market and is treated as a fixed interchange schedule at the MW level determined in the day-ahead market. Cleared MW amounts for dispatchable interchange schedules will be provided to the participant after the day-ahead market run. SPP proposes participants be required to update tags to reflect the market's cleared MW amount but could investigate automatically adjusting the applicable tags as the market operator.

All dispatchable interchange schedules, both import schedules and export schedules, are settled at LMPs determined in the day-ahead market at the appropriate external interface settlement location, representing the interface between Markets+ and the applicable external balancing authority.

During phase one, SPP and stakeholders will investigate expanding dispatchable interchange schedules beyond the day-ahead market into real time and determine if it will be included at Markets+ launch or should be investigated as a post go-live enhancement.

4.2.3 IMPORTS

The term import only describes those tags that come into the Markets+ footprint from an external entity (e.g., CAISO or other non-participating balancing authority). Imports can sink in any participating balancing authority and will settle at the interface point where the tag first enters the Markets+ footprint (i.e., the first scheduling entity on the tag that is a participating balancing authority). Consistent with other organized energy markets, Markets+ does not deliver external generation to a specific load inside of the footprint. The import is delivered to Markets+ and the market serves the load. The Markets+ systems use the sink on the tag to determine the settlement location to settle the tag.

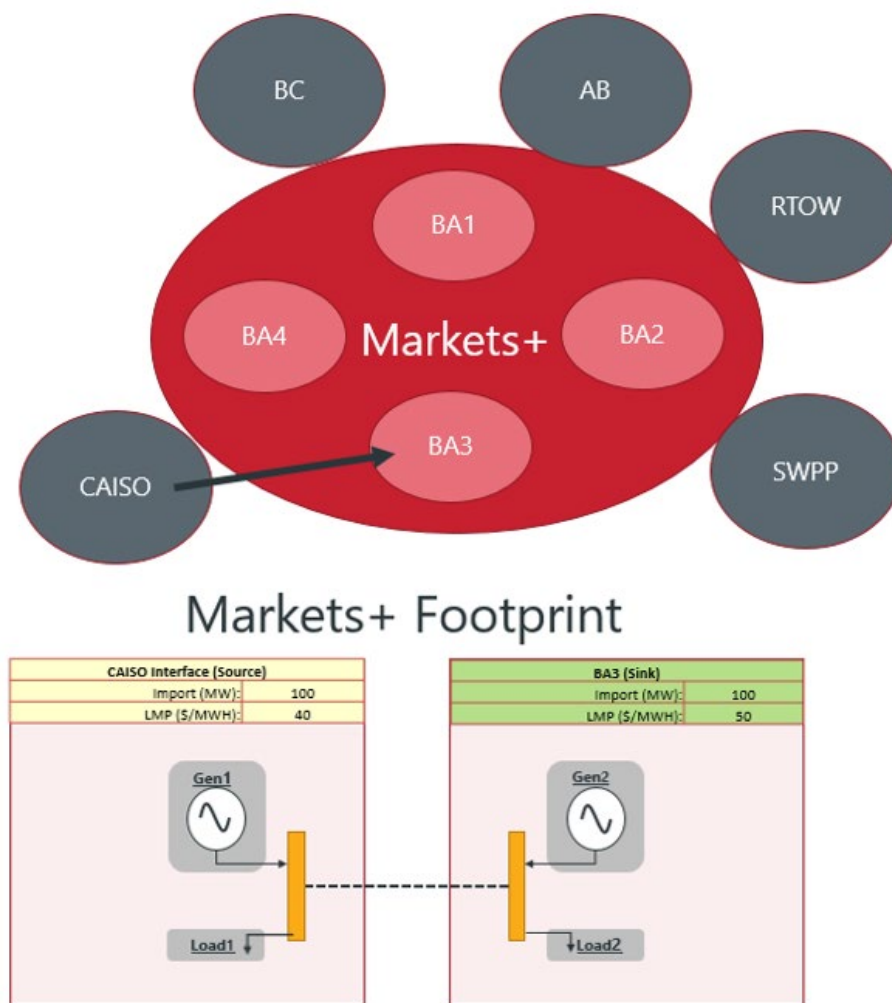


EXHIBIT 8: MARKETS+ IMPORT

Transaction settlement = import MW x **interface LMP** = 100 x 40 = \$4,000 (charge)

4.2.4 EXPORTS

The term export only describes tags that leave the Markets+ footprint from an internal entity. The export tag can source in any participating balancing authority. Markets+ identifies export tags by the last scheduling entity that is a participating balancing authority. The interface point at the Markets+ footprint border is used to determine the LMP to settle the export tag. Markets+ does not recognize or use the external loads that receive generation from Markets+ for systems or settlements. The Markets+ systems use the source on the tag to determine the settlement location for settlements. Consistent with other organized markets, the export tag results in delivery from the Markets+ generation fleet, not an individual generator or source.

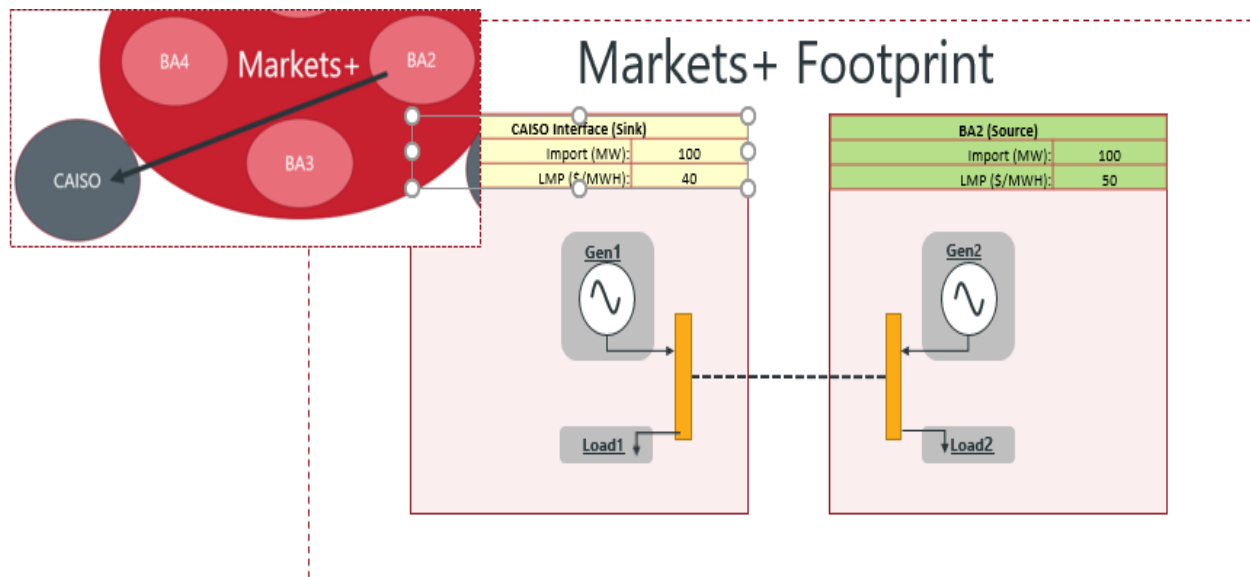


EXHIBIT 9: MARKETS+ EXPORT

Transaction settlement = export MW x interface LMP = $-100 \times 40 = -\$4,000$ (credit)

4.2.5 WHEELS

The term wheel or wheel through describes tags primarily external to the Markets+ footprint, even though they may cross multiple boundaries between balancing authority and TSP inside the market. Markets+ does not recognize or account for external sources or sinks on wheel-through tags for centralized unit commitment or dispatch. The interface point of the tag's entry and exit (Markets+ footprint) are used to determine the LMP difference as needed for settlements.

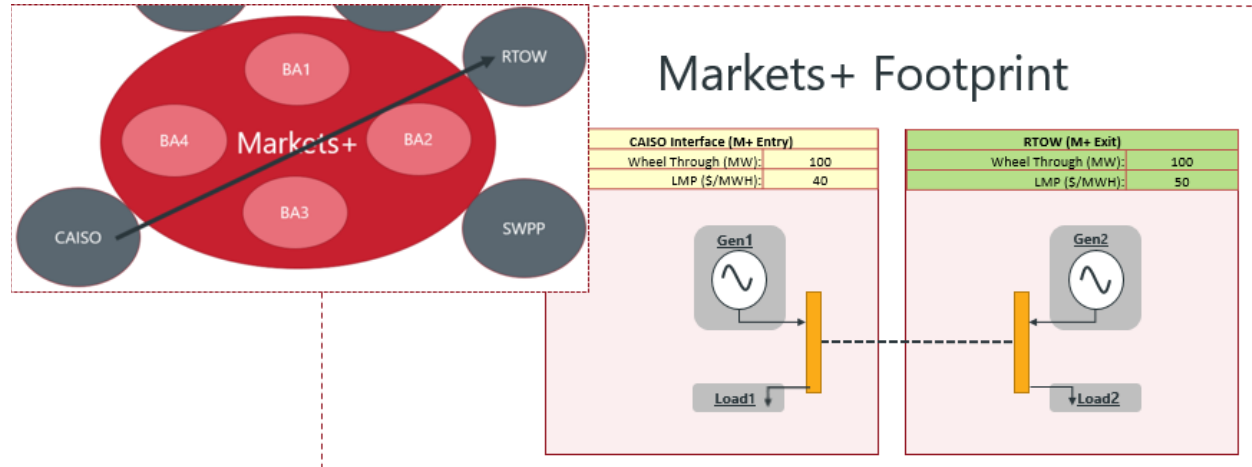


EXHIBIT 10: MARKETS+ WHEEL

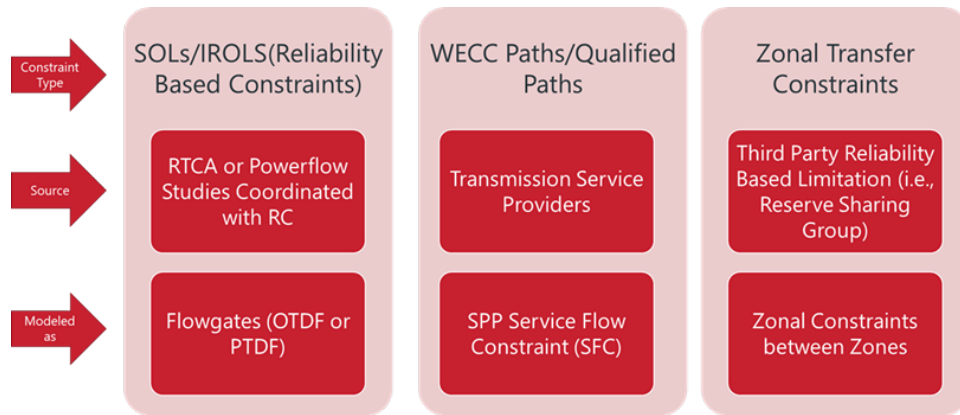
Wheel-through transaction settlement = wheel-through MW x (exit interface LMP – entry interface LMP) = 100 x (50 - 40) = \$1,000 (charge)

4.2.6 MARKETS+ IN-AND-OUT TAGS

In and out tags include all tags that source and sink within the Markets+ footprint but cross boundaries into and out of the Markets+ footprint. In-and-out tags may be treated as internal transactions and settled as market flow, or in-and-out tags may be treated as import/export tags. SPP proposes these types of transactions are discussed in detail once the anticipated Markets+ footprint is identified.

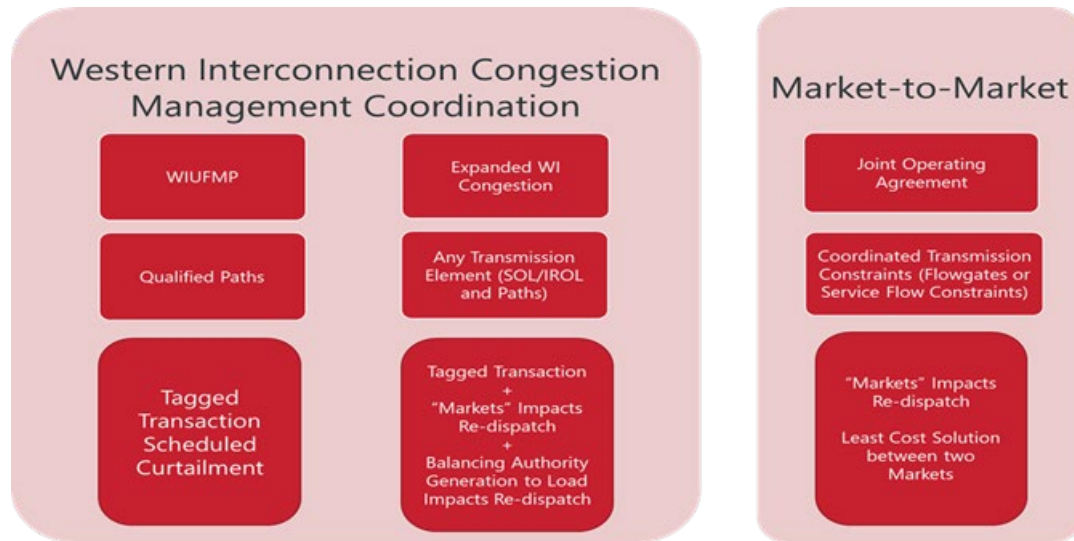
4.3 CONGESTION MANAGEMENT

SPP's market assesses transmission deliverability when making commitment and dispatch decisions in SCUC and SCED. The transmission constraints are modeled as flow gates that represent equipment limitations, SOLs or IROLs. Transmission constraints may represent any identified WECC paths or zonal transfer limitations, representing service contractual limitations granted to the Markets+ entities. These constraints would be modeled as service flow constraints. SPP captures any cost to redispatch around these transmission constraints as congestion costs represented in the marginal congestion cost (MCC) component of the LMP.



Congestion management should be coordinated with entities outside the Markets+ footprint to ensure equitable redispatch and curtailment across the bulk electric system in the Western Interconnection. SPP processes allow for any coordination reflected in operating guides, Western Interconnection Flow Mitigation Process (WIUFMP) or through a joint operating agreement if established with neighboring entities (e.g., market-to-market agreement or other flow gate or path coordination agreements).

SPP will facilitate, lead and advocate for seams coordination with fair and equitable outcomes across the Western Interconnection, including the expansion of the Western Interconnection coordination congestion management and other seams coordination agreement where appropriate.



4.4 RESERVE SHARING GROUP

Markets+ does not include reserve sharing groups (RSG) or balancing authority services. Each participant is responsible for meeting their obligation to the appropriate RSG and the balancing authority. SPP proposes the contingency reserves (CR) capacity assigned for the RSG and

balancing authority CR obligations is held back from the market. Markets+ will not commit or dispatch the capacity held back by CR. Details for the interoperability between RSG programs, CR deployments by BAs and Markets+ dispatch will be incorporated into phase one.

Participants will continue to be required to ensure the deliverability of the CR. Any transmission service capacity needed to facilitate CR deployment may reduce the deliverability of the energy product dispatched by the market.

Markets+ does not intend to interfere with any RSG construct. The service offering does not include a CR co-optimization across the market, and the obligation to clear and deploy reserves will continue to be a balancing authority responsibility respecting the RSG rules.

4.5 DIVISION OF RESPONSIBILITIES/NERC FUNCTIONAL MODEL

A summary of each functional entity's focus within an organized market construct is discussed in table 41. The list does not include all information or tasks required for the functional areas. The relevant functional entities discussed in this document are the reliability coordinator (RC), balancing authority (BA), transmission service provider (TSP), transmission operator (TO), generator owner/generator operator (GO/GOP) and market operator (MO).

The market operator is responsible for the centralized commitment and dispatch of resources. The market operator does not assume the responsibilities of the RC, TOP or BA. Though the market operator may facilitate and coordinate these responsibilities, entities are still responsible for their respective functions and responsibilities as recognized in the North American Electric Reliability Corporation (NERC) functional model and as the applicable entities in the NERC reliability standards.

Each of the aforementioned functional entities will continue to be responsible for performing their functions and responsibilities as outlined by their governing document, business practices and NERC and WECC standards.

Reliability Coordinator	Monitor and grid management, coordinate emergency operations, manage system restoration, perform reliability analysis, coordinate congestion management, curtail interchange schedules.
Balancing Authority	Support interconnection frequency, situational awareness, regulation service deployment, load-following through economic dispatch, interchange implementation and schedule control, control net actual interchange.
Transmission Operator	Operates or directs operation of transmission facilities, responsible for transmission system restoration and mitigating transmission emergencies. May coordinate congestion management with the market operator.

Transmission Service Provider	Receives and evaluates TSRs per the Open Access Transmission Tariff (OATT), determines and posts ATC values, administers OASIS for respective tariff rules, approves/denies TSRs, approves interchange transactions from the TSP perspective, allocates transmission losses.
Transmission Owner	Owns and provides for the maintenance of its facilities, specifies equipment operating limits, supplies this information to the TSP, RC, TP and PC. In some cases, has contracts or interconnection agreements with generators or other transmission customers.
Generator Owner/Operator	Operates or directs the operation of generation facilities, supports the needs of the BES up to the limits of the generating facilities in its purview, maintains generation schedules, fuel supplies and frequency support.
Purchasing-Selling Entity	Arranges for and takes title to energy products that it secures from a resource for delivery to a LSE, arranges for transmission service with the TSP and initiates bilateral interchange between BA areas.
Load-Serving Entity	Arranges for the provision of energy to its end-use customers, may also be GOs and can self-provide or have contracts with other GOs for capacity and energy to serve LSE customers, or purchase capacity and energy from non-affiliated GOs through a PSE.
Market Operator	May implement instructions from BA/TOPs utilizing the SCED, follow respective tariffs, and perform the role of resource integration following market and tariff rules. The MO is not a NERC-defined reliability function and does not have compliance requirements with NERC.

The market operator will have key interactions with these entities to exchange necessary information and implement any required instructions or attribute changes into the market system to ensure the system's reliability and respect equipment limitations and transmission service limitations where appropriate. Table 4-2 summarizes possible points of interaction with the market operator.

Reliability Coordinator	Depending on the business needs and willingness of the RCs, the MO may be able to communicate with the RC for effective and more streamlined communication. This would likely be limited to congestion management coordination. This does not replace the need for coordination between the RC and other entities like the BA, GOP and TOPs.
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Balancing Authority	<p>In Markets+, SPP would offer commercial services such as integrating resources ahead of the operating window, typically a five-minute interval horizon and settlement after implementing interchange and dispatch. The market implements the resource plan in the operating window, making adjustments as necessary, to meet reliability requirements and balancing needs economically and following established market rules.</p> <p>In Markets+, close coordination between the market operator and the balancing authorities is expected. The market operator performs resource integration tasks and is assigned the following:</p> <ul style="list-style-type: none"> • Determining the generation dispatch plan (unit commitment) ahead of time. • Integrating scheduled interchange into that generation plan. • Provide the generation dispatch plan to the balancing authority ahead of RT. • Balancing authorities will continue to be responsible for BAL standards.
Transmission Operator	Coordination with the MO may be appropriate to communicate transmission system or generation limitations that must be enforced in the market system to mitigate reliability conditions.
Transmission Service Provider	Markets+ may require the TSPs to communicate the total transfer capability and available transfer capability on transmission constraints and the transmission rights held by participants.
Transmission Owner	The entity that owns and maintains transmission Facilities that may require coordination with the MO for Transmission Operator or Transmission Service Provider roles.
Generator Owner/Operator	GOPs may receive dispatch instructions from the market system to streamline the communication to the generation fleet.
Purchasing-Selling Entity	The SPP MO has an indirect relationship with the PSE because SPP MO is not the TSP or BA
Load-Serving Entity	The SPP MO has indirect relationship with the LSE because SPP MO is not the TSP or BA.

4.6 SEAMS

SPP understands appropriate consideration of market seams issues is a key element of the Markets+ design. Absent a move to a full RTO with BA/TSP consolidation, SPP expects many of the existing seams observed in the west will continue to exist in the future, such as seams between BAs, TSPs, bilateral markets and organized markets and multiple organized markets.

Markets+ provides a valuable opportunity to more effectively manage these seams to support and enhance reliability for the western grid, while producing more equitable outcomes and increasing benefits for Markets+ participants relative to today. This is possible because the Markets+ design proactively contemplates support for existing bilateral transactions and the OATT transmission framework, while SPP as market operator will work in close coordination with TSPs and BAs to clearly define and perform the roles and responsibilities assigned to each entity.

Perhaps most importantly, Markets+ will enable a peer-to-peer approach to manage seams issues between markets (including CAISO markets) to ensure the interests and priorities of Markets+ members are appropriately considered in resolving seams issues and allowing SPP and its stakeholders to achieve improved trade outcomes relative to the status quo.

To support this objective, SPP proposes to form a seams task force supported by SPP staff and stakeholders to support seams management and future negotiation efforts.

5.0 TRANSMISSION

The market operator will be responsible for economical dispatch of generation throughout the market footprint. The transmission service provider (TSP) and transmission owner (TO) will continue to own and operate the transmission system. The market region is broader than a single transmission provider's system and uses transmission and resources differently than traditional bilateral operations. Regional, non-pancaked transmission use facilitating the receipt of energy from any resource in the market region to meet load obligations is necessary to facilitate the most economical market solution. TSPs within the Markets+ footprint will maintain their open access transmission tariff (OATT), administer their OASIS and continue to sell firm and non-firm transmission service as they normally do before the market window. Markets+ will economically dispatch energy across the market footprint using the flow-based transmission capacity less any capacity not available for market use (e.g., capacity owned by a non-market participant, reliability set asides, etc.). Markets+ depends upon the TSP to provide accurate transmission service reservation (TSR) data as needed to run the market systems and settle market energy with market participants. This information will be provided via a secure, electronic format.

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 TSPs whose

systems make up the wheel. Revenues associated with imports, exports and wheel through-and-out transactions will be applied to the TSP's annual transmission revenue requirement (ATRR) as a revenue credit toward overall ATRR and will not be part of any revenue recovery for market use of transmission.

The Markets+ system will create dispatch signals to distribute market flow between balancing authorities within Markets+. These dispatch signals will be associated with dynamic tags between the balancing authorities. Since dynamic tags will be between balancing authorities, these transactions will require a TSR to document the transaction on the TSP's OASIS.

5.1 MARKET TRANSMISSION USE

Markets+ will facilitate the optimization of the full capability of each TSP's facilities through the transmission service sold and unsold by each participating TSPs.²⁹ Importantly, TSPs will continue to sell service as normal, pursuant to their respective OATTs. Firm and short-term firm and non-firm services will continue to be priced based on each TSP's OATT process. For example, intra-hour as-available services will continue to be priced at "\$0.00" – similar to the practice used in WEIS and WEIM for joint dispatch services. As such, Markets+ will be optimizing a combination of firm and non-firm services provided by TSPs. TSPs and the Market+ Operator will coordinate with neighboring non-participating TSPs on congestion management needs to respect transmission priority of services and the details for communication needs and any changes in business practices will be identified during phase one.

In exchange for enabling Markets+ to optimize the participating TSPs transmission services (sold or unsold), the Markets+ operator will collect a market charge for all transactions in the market – generation and load volumes – and distribute the revenue to each TSP.

As discussed above, Markets+ will utilize regional market dispatch to serve all participating load, likely causing revenues from short-term firm and non-firm transmission capacity sales to decrease. A new revenue recovery mechanism, Market Transmission Use (MTU),³⁰ will facilitate the collection and distribution of revenue through a market charge applied to all energy and

²⁹ Limited exceptions (carve-outs) will be made for transmission service owned by transmission customers of the participating TSPs based on rules developed in phase one by the Market+ Transmission Working Group. More details are included on this topic in Section 5.4.

³⁰ SPP has used Market Efficiency Usage, Regional Transmission Service, and Market Transmission Service and other terms to describe this feature. To continue clarifying intent and purpose, SPP modified the terminology again to Market Transmission Use because of confusion during the stakeholder process regarding whether Market Transmission Service is actually a service or a recovery mechanism or both. MTU is not a service with an associated OATT rate. It is a billing determinant used to collect and distribute to the participating TSPs for crediting to their respective Annual Transmission Revenue Requirements. The transmission service optimized by Market+ is sold by the participating TSPs pursuant to each respective OATT.

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. MTU revenue will be referenced in participating TSP tariffs and will be applied as offsetting revenue to their total ATRR.

The Markets+ Transmission Working Group will determine the OATT provision used to reference MTU revenue recovery in each TSP's respective OATT. SPP's tariff filing will reference MTU in each Markets+ participant's OATT. Market use compensation is provided from the market via an MTU billing determinant using a combined revenue requirement derived from participating TSP OATTs as described below. The revenue requirement for MTU will be established annually and is discussed in further detail below. The per-megawatt hour (MWh) charge for MTU will be a fixed rate based on the total estimated amount of energy cleared in the real-time market and will apply to all energy (generation and load) in the Markets+ footprint. MTU recovery true up will be applied to future year MTU rates.

The initial MTU revenue recovery amount is defined by a transmission provider's qualified recovery amount (QRA), which is based on the revenue a TSP historically received from sales of short-term firm (STF) and non-firm (NF) transmission service. Any under or over collection of MTU revenue collected by the market would be applied as an adjustment by the respective TSP when calculating future ATRRs and associated transmission rates. An average of a transmission provider's previous three year STF, NF and total ATRR will be used to establish the initial QRA.

$$\text{Qualified Recovery Amount (QRA)} = \text{Avg}(\text{Prev 3 Years' TSP STF Revenue} + \text{TSP NF Revenue})$$

A ratio of STF plus NF versus total ATRR will be calculated for each TSP, known as a qualified revenue ratio (QRR). This ratio will be applied to current and future year ATRR to account for changes in ATRR over time. For example, if a TSP's initial total ATRR is \$120 million with \$12 million in short-term firm and non-firm sales, the ratio of STF+NF versus total ATRR is 10%. The 10% ratio will be applied to the ATRR for current and future years to determine MTU revenue recovery. Should ATRR go up to \$140 million in a future year, for example, the amount of qualified revenue would go up to \$14 million based on the TSP's established MTU QRR applied to the TSP's updated ATRR. SPP will use an average of the previous three years' STF and NF revenue recovery (initial QRA) to establish the MTU QRR for each participating TSP versus the average of the TSP's total ATRR for the previous three years. The Markets+ Transmission Working Group will establish protocols for updating the QRR calculation in future years.

$$\text{Qualified Revenue Ratio (QRR)} = \frac{\text{Avg}(\text{Prev 3 years' STF} + \text{NF})}{\text{Avg}(\text{Prev 3 Years' Total ATRR})}$$

While traditional short-term firm and non-firm sales of transmission service will likely decrease with Markets+, it is unlikely sales of either transmission product will completely cease. To address this condition, a recovery scaling factor (RSF) will be applied to mitigate potential over collection for MTU. The Markets+ Transmission Working Group will establish the RSF value on participant ATRR data and will review and adjust based on the MTU review process established

by the group. Any changes to either the MTU QRR or RSF will be applied to future year calculations of the MTU RRA. At no time will the RSF exceed 100%.

Recovery Scaling Factor (RSF) = Factor between 0 and 100%

MTU Revenue Recovery Amount (RRA) = (ATTR * QRR) * RSF

5.2 PARTIAL YEAR ENTRY

If an entity has established a market entry date that does not coincide with the start of the MTU revenue recovery year, a partial year rate can be determined and applied as long as NEL and generation information is provided for the rate year per the information timing requirements established for MTU revenue recovery calculation.

5.3 TRANSMISSION REVENUE DISTRIBUTION FOR MARKETS+

The method of revenue distribution to TSPs is based on a ratio of each TSP's MTU QRA to the total MTU QRA being recovered.

$$MTU \text{ Revenue Distribution} = \frac{TSP \text{ MTU RRA}}{Total \text{ MTU RRA}}$$

5.4 USE OF TRANSMISSION SERVICE FOR MARKET DISPATCH

Markets+ compensates for the use of transmission to deliver energy between participating generators and load. Transmission used to deliver market energy will be comprised of all transmission that is unsold by transmission providers within the Markets+ footprint, Markets+ participants' rights not used for deliveries outside of the Markets+ footprint or otherwise unscheduled in addition to service associated with intra-market schedules submitted to the market (i.e., the total transmission capabilities of those entities participating in Markets+ less any non-market and set-aside transmission capacity). At 0X00 MPT³¹, TSPs will communicate transmission availability information to the market operator for use in subsequent market runs. The Markets+ Transmission Working Group (MTWG) will establish transmission set-aside

³¹ To be determined during phase one

protocols to ensure maximum transmission available for market use while respecting transmission customer autonomy.

SPP recognizes that some transmission customers within the Markets+ footprint may have long-term commitments to external balancing areas or markets that uses transmission service sold by TSPs participating in the Markets+. SPP's approach to transmission capability in the Markets+ is a concept of "all transmission capability is in the market, unless explicitly carved out." During phase one, SPP proposes that the MTWG develop the policy and timing requirements necessary for transmission customers to identify explicit carve outs from Markets+. For example, it may be appropriate to support a process to enable a transmission customer to notify a Markets+ TSP that its PTP transmission service rights will be used to support transfers to another BAA or market footprint for a given calendar year. For the given calendar year, the TSP and Markets+ systems could be configured to carve out the PTP transmission service owned the non-participating transmission customer for the calendar year.

Network transmission service is based on peak demand and not a specific point of receipt (POR) or point of delivery (POD) path. The network customer designates generating units to serve network load under its network transmission service. If Markets+ delivers lower-cost energy to the customer's network load rather than via a network customer's generating units, the generation is essentially delivered from non-designated network resources. The network customer will need to maintain network transmission service in the same fashion as today to facilitate energy delivery to their network load. MTU will facilitate the delivery of the least-cost resources, subject to transmission availability, to network load irrespective of generation location and transmission provider area in the Markets+ footprint.

Point-to-point (PTP) service is sold on a specific POR/POD, meaning a specific POR/POD is shown on the PTP TSR. MTU functions as a redirect of firm transmission in this instance and allows for delivery of least-cost energy, subject to transmission availability, from across the entire Markets+ footprint.

5.5 DAY-AHEAD TRANSMISSION

Once transmission availability for market use is determined, a security-constrained economic dispatch solution (SCED) will be derived based on DA bids and offers while respecting OATT rights committed before the day ahead. All transmission made available for the day-ahead market from the transmission service provider should remain available until after the day-ahead market completion to avoid over selling transmission. SPP will communicate the results of any price sensitive dispatchable schedules to participants with the results of the day-ahead market. Market participants should update their tags so the TSP can reflect the remaining available transmission in their respective OATT processes leading up to the real-time operating window.

5.6 REAL-TIME TRANSMISSION

To produce the most efficient market solution in real time, the Markets+ security constrained economic dispatch (SCED) will use MTU to make use of all available participating transmission capacity in the market footprint to optimize the commitment and dispatch of participating generators. Markets+ will redispatch via the SCED to manage transmission constraints loading using real-time shift factors on a flow-based basis. MTU will not displace higher priority transmission service offered by a participating transmission provider. Instead, MTU makes intra-hour use of otherwise unsold out-of-the-market transmission capacity, the existing network and point-to-point transmission service previously procured by transmission customers in a manner similar to non-firm redirect use of firm transmission. Markets+ use of MTU will be compensated at the MTU rate and will be based on all energy and load cleared and settled in the real time market.

MTU cannot be used as a substitute for point-to-point or network integration transmission service to serve load or for off-system sales of capacity or energy to provide direct or indirect transmission service to a third party. For off-system purchases and sales, customers must obtain transmission service from the applicable transmission service providers, as needed, to import energy from outside the market footprint or to export off-system sales, following FERC and North American Energy Standards Board (NAESB) regulations.

5.7 DAY-AHEAD CLEARING PROCESS

Purchasing-selling entities (PSEs) may continue to submit current and next day TSR requests to their TSP OASIS during the SPP Markets+ day-ahead clearing. It is expected transmission offered in the DA market for the next day is not resold before posting of the DA market results for the TSP to have an accurate ATC calculation to approve or deny new short-term requests for the next day period. TSPs will hold confirmation on next day transmission requests until the DA market completes to avoid over selling.

Once the Markets+ day-ahead clearing process is complete, the SPP system will send a tag market adjustment directly to day-ahead Markets+ BA-to-BA dynamic tags and for any submitted price sensitive imports or exports. For example, if the tag is not cleared for the total amount offered, the system will adjust the MW on the tag to the correct cleared MW amount. The PSE will then approve the adjustment as appropriate. Market transmission use will be communicated to TSPs via a secure, electronic format.

Once the day-ahead tags have been market adjusted, a PSE/TC is free to make an additional adjustment to their tags to free up any TSR capacity not used in the day-ahead market. The PSE/TC may begin submitting new short-term TSR on their TSP OASIS and tag for real-time operations.

The PSE will continue submitting TSR and tags under existing operating guidelines for the remainder of the operating day and beyond.

6.0 MARKET SETTLEMENTS

In 2020, SPP implemented a new settlement system that handles all market and transmission settlements in the SPP footprint. The SPP Settlements Management System (SMS) is a proprietary system owned and maintained by SPP, which eliminates the reliance on external vendors. This allows SPP to decrease implementation time, cut costs and provide a system that is flexible, adaptable and scalable to fit settlements needs across the footprint. Markets+ settlements could be accommodated in our current SMS without requiring any new technology.

The proposed Markets+ settlement timelines and processes outlined below are the high-level overview of current SPP market settlements as defined by the SPP's current OATT and market protocols in the SPP RTO. The settlement system is flexible, but based on previous experiences and member suggestions, SPP recommends keeping the same guidelines listed below, which drive our current market processes. These guidelines can be adopted for Markets+ or adjusted to accommodate design differences if required to better suit the participants' needs.

6.1 SETTLEMENT TIMELINES

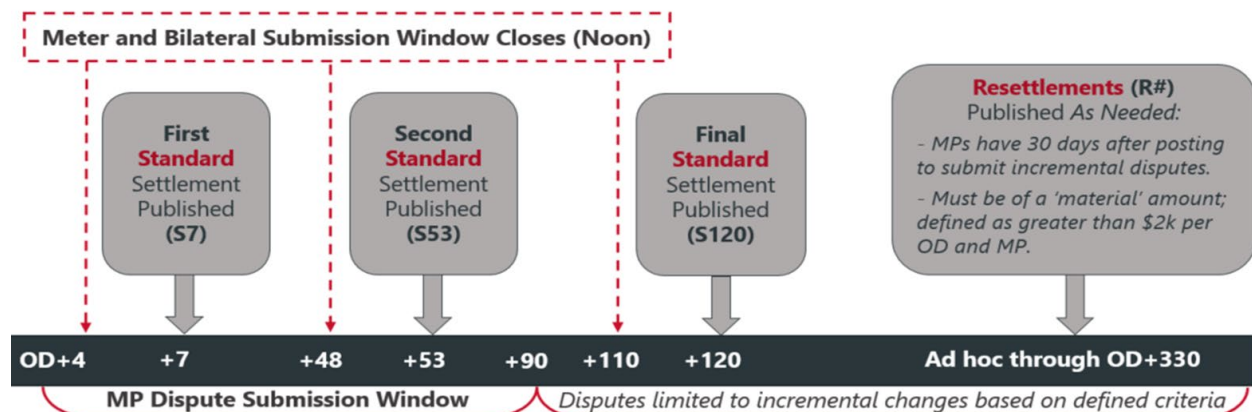


EXHIBIT 11: SETTLEMENT TIMELINES

There will be three standard daily postings: S7, S53 and S120, where the number indicates calendar days after the operating day. For example, S7 posts seven days after the operating day. There will not be any postings on weekends or holidays. These will move to the next business day. Meter data are due OD+4 (S7), OD+48 (S53) and OD+110 (S120). The S120 allows for

sufficient time for meter data to be finalized. Any meter updates after the S120 will be limited to submitted and granted disputes according to the dispute guidelines.

SPP will create settlement reports daily for each market participant and associated asset owner, detailing the cost responsibility for each.

- Settlement statements are produced for each settlement date (calendar posting date) and provide a summary of the total and net charge or credits for each settlement type (S7, S53, S120, R#). Statements can be used by the market participant to reconcile their weekly invoice amounts.
- Settlement determinant reports are produced for each operating date and asset owner and provide sufficient detail to verify the calculated settlement amounts. Determinant reports contain the settlement location and interval date used in the settlement calculations, in addition to the calculated charge or credit for each settlement location.

6.2 COMMERCIAL MODEL

The commercial model describes the financial market relationships and determines how data are mapped in the financial settlement process. This allows SPP to directly transact with the entity registered in the market while removing the financial responsibility from the BA. For example, if a BA has five customers, each customer could register as a MP. These five MPs can then decide how they want to model their generation and load independently of each other.

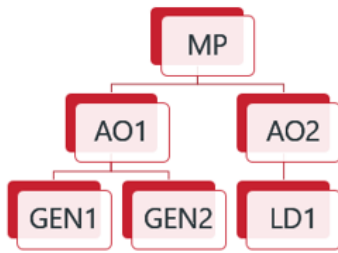
Each MP is billed separately. By having this concept, financial freedom allows entities to decide how line items should be broken out on the statements, making it easier to identify specific transactions.

Market Participant (MP) – The highest level in the commercial model and is the entity that is financially obligated to SPP for settlement of the market. The MP receives the weekly invoice.

Asset Owner (AO) – The next highest level in the commercial model and typically, but not necessarily, represents a company. A company may choose to be registered as more than one AO. A single AO can contain any combination of generation and load and can be financial only (FO). Asset owners must be represented by an MP. Settlement charges are summarized by AO and MP in the settlement statements.

Settlement Locations (SL) – The next hierarchical level in the commercial model and has a relationship to a pricing node (single or aggregate). Energy is settled at the corresponding settlement location's locational marginal price (LMP). This provides the market participant flexibility regarding how their resources and loads are settled.

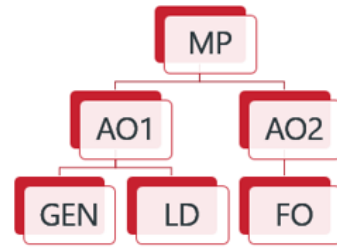
Example 1



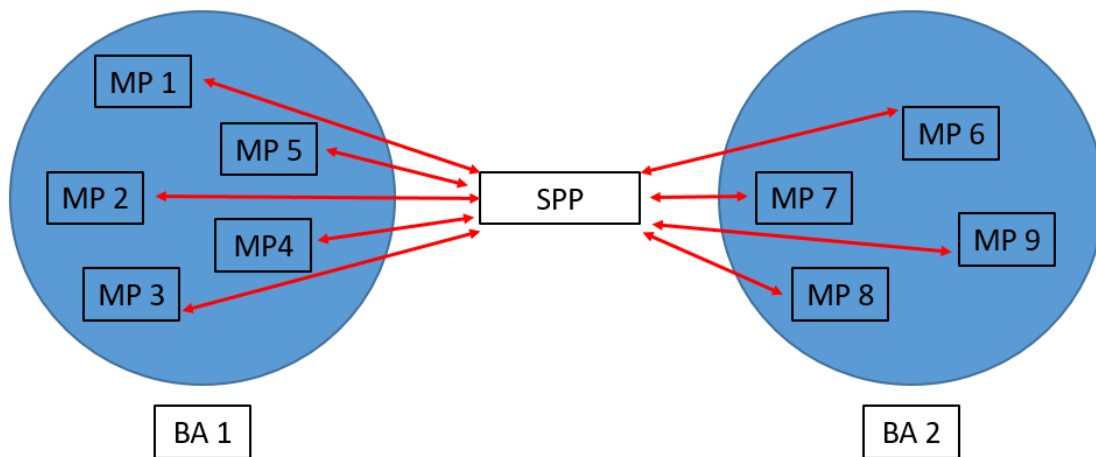
Example 2



Example 3



Direct Billing Example



6.3 SETTLEMENT STATEMENT PROCESS

6.3.1 DAILY SETTLEMENT STATEMENT

Settlement statement(s) will be made available for each settlement day (calendar posting day) and published for market participants and associated asset owners electronically through the SPP portal on business days and include charges and credits by asset owner and operating day. The settlement statement will contain charges and credits for each standard settlement type (S7, S53, S120) in addition to any scheduled resettlements (R#) posting for a given calendar day.

For each market participant, settlement statement(s) will denote:

- Operating day

- Market participant identifier
- Associated asset identifier
- Settlement type (S7, S53, S120, R<ddd>, where ddd represents the number of days after operating day)
- Statement version number
- Unique statement identification code
- Market services settled

6.3.1.1 DETERMINANT REPORTS

Determinant reports will be made available to market participants and their associated asset owners electronically through the SPP portal on business days. Determinant reports contain the settlement location and interval data used in the settlement calculations and provide sufficient detail for the asset owner to verify the calculated settlement amounts.

6.3.1.2 RESETTLEMENTS

SPP will schedule resettlements as needed to correct a previously posted settlement statement for an operating day. Resettlements will be limited to the following reasons:

- The correction of data resulting from an SPP software error and/or an SPP data error per the discretion of the transmission provider in accordance with the rules specified under the tariff.
- A granted dispute per the approved guidelines.
- Per court order or Federal Energy Regulatory Commission (FERC) order.

Resettlements are limited to 330 days following the operating day, allowing for a dispute period following the relevant resettlement statement before reaching the 365-day limit set by the tariff. The 365-day limit enables market participants to have some level of finality that the financial books can be closed on days beyond that period (barring a FERC order or instruction).

Market participants can refer to resettlement statements according to the number of days following the operating day that the results are posted to the portal, e.g., a resettlement posted 200 days following the operating day would be referenced as the R200 resettlement.

SPP will post a settlement calendar on the portal which will include any scheduled resettlements.

6.3.2 SETTLEMENT INVOICE

SPP prepares weekly settlement invoices from settlements statements on a net basis with payments made to or from SPP. Each market participant with a net debit balance will pay any net debit whether or not there is any settlement and billing dispute regarding the amount. Each

market participant with a net credit balance will receive the balance shown on the settlement invoice adjusted for balances not collected from market participants with net debit balances.

6.3.3 TIMING AND CONTENT OF INVOICE

SPP will electronically post an invoice based on any scheduled settlement statements or resettlement statements produced since the prior settlement invoice for each market participant.

- SPP will group invoice items by type of statement (S7, S53 and S120 scheduled settlements and resettlements) and will sort by operating day within each category. Each settlement invoice will contain the following: Market participant ID – the name, address and contact information for the market participant being invoiced.
- Net amount due/payable – the aggregate summary of all charges owed by or due to a market participant.
- Amount due/payable by asset owner, operating date and settlement date — the aggregate of charges owed by or due to an asset owner listed by operating day, which is identified by calendar date.
- Time periods – the time period covered for each settlement statement run date identified by a range of calendar dates.
- Run date – the date the invoice was created and published.
- Invoice reference number – a unique number generated by SPP for payment-tracking purposes.
- Settlement statement ID – an identification code used to reference each settlement statement invoiced.
- Payment date and time – the date and time invoice amounts are to be paid or received.
- Remittance information details – details including the account number, bank name and electronic transfer instructions of the SPP account to which any amounts owed by the invoice recipient are to be paid or of the invoice recipient's account to which SPP will draw payments due.
- Overdue terms – the terms applied if payments are received late.
- Late fees.
- Miscellaneous charges from tariff billing not otherwise covered above with details provided or referenced on what the miscellaneous charges include and how they are derived.

6.3.4 INVOICE CALENDAR

Weekly invoices will be distributed every Thursday by no later than 8 a.m. CPT, except for holidays. Weekly invoices will include the seven daily settlement statements (scheduled settlements and any resettlements) produced for the previous Wednesday through Tuesday cycle. Market participant balances owed to SPP are due by 5 p.m. CPT on the first Wednesday following the Thursday invoice date. Balances owed by SPP to market participants will be paid on the second Friday following the invoice date by 5 p.m. CPT.

6.4 DISPUTES

A market participant may dispute items outlined in any settlement statement. The dispute must be filed using the request management system with the following minimum content:

- Request type
- Subject
- Full description
- Statement type
- Charge type
- Settlement location
- Operating day
- Start interval
- End interval
- Dispute amount
- Proposed resolution

6.4.1 DISPUTE SUBMISSION TIMELINE

A market participant may dispute the settlement of any operating day within 90 calendar days after the posting of the S7 scheduled settlement statement for that operating day. In the case of the S120 scheduled settlement and any resettlement statements, a market participant may only dispute incremental material changes that occur between the postings of:

- The S53 and S120 scheduled settlements

- The S120 scheduled settlement and the first resettlement statement
- Two consecutive resettlement statements

Material is currently defined as a dispute when more than \$2,000 is at issue for the market participant for the impacted operating day. A dispute relating to an S120 scheduled settlement or resettlement statement must be filed within 30 calendar days following the posting of the applicable settlement statement the market participant wishes to dispute.

6.4.2 DISPUTE STATUS

Each dispute will have a defined status. Valid status designation includes:

- Open and closed: A dispute will be deemed open when submitted promptly and completely. Closed is the final status for all disputes.
- Denied: The dispute will be denied if SPP concludes the information used in the dispute is incorrect. If the market participant is not satisfied with the outcome of a denied settlement and billing dispute, they may proceed to external arbitration as described in the dispute resolution section of the tariff.
- Granted: SPP may determine a settlement and billing dispute is granted. Upon resolution of the issue, the settlement and billing dispute will be processed on the following prescribed settlement statement for the operating day.
- Granted with exceptions: SPP may determine a settlement and billing dispute is granted with exceptions when the information is partially correct. SPP will provide the exception information to the market participant.

6.5 INVOICE PAYMENT PROCESS

6.5.1 OVERVIEW OF PAYMENT PROCESS

Payments will be made in a two-step process where:

- All settlement invoices due with net debits owed by market participants are paid by 5 p.m. CPT of the first Wednesday following the Thursday invoice date.
- All settlement invoices due with net credits owed to market participants are paid by 5 p.m. CPT of the second Friday following the invoice date.

Payments due to SPP and payments due to market participants will be made by electronic funds transfer (EFT) in U.S. dollars.

6.6 SETTLEMENT CATEGORIES

The following (dependent on the approved market design) categories will be included in the daily settlement across day ahead and/or real time:

- Energy (physical and virtual)
- Flex products
- Congestion rents
- Make-whole payments
- Greenhouse gas
- Over collection of losses
- Out-of-merit energy
- Market transmission service use
- Import/export transactions
- Miscellaneous adjustments
- Revenue neutrality uplift
- Applicable distribution charges

Three distribution methods can be applied for distributing uplift: Load ratio share, market activity and cost causers (deviators). These distribution methods can be applied to the entire market or to the impacted balancing authority. Load ratio share will allocate costs to any entities with withdrawals (load or exports) from the market footprint. The market activity will distribute costs to any entity participating in the operating day market, defined as generation, load, imports, exports and virtual activity. The last method is cost causation. This will allocate costs to any entity that deviates in real time from the day-ahead market awards or for entities with generation that deviates from real-time dispatch. SPP will work with stakeholders to determine how to use these various methods to apply cost allocation correctly and fairly across the different distribution charge types.

7.0 MARKET MONITORING

SPP's Market Monitoring Unit (MMU) performs the market monitoring role for SPP's RTO and SPP's Western Energy Imbalance System market in the Western Interconnection. While extending this role for the MMU into Markets+ would be the organic structure for SPP considering its experience and success, expanding the market monitoring structure to include an external advisor to the MMU could be supported as a hybrid approach.

7.1 BACKGROUND AND EXPERIENCE

The SPP MMU is the market monitor for the SPP Integrated Marketplace and the Western Energy Imbalance Services (WEIS) market. MMU staff worked with SPP staff and market

participants during the design and implementation of the SPP Integrated Marketplace and WEIS market and continues to work with SPP to ensure its markets are efficient and fair. The MMU staff possess a diverse range of skills and expertise, including degrees in engineering, economics, finance, accounting and information technology.

MMU staff comment on numerous SPP filings at Federal Energy Regulatory Commission (FERC) regarding proposed changes to the SPP and WEIS tariff and provide independent comments on FERC notices of proposed rulemaking, notices of inquiry and FERC orders. Numerous examples of MMU comments and positions on market issues can be found in Section 1.5 of this service offering.

The MMU remains engaged in appropriate stakeholder groups and discussions. The MMU strives to be transparent when commenting in these groups, ensuring SPP staff and market participants are aware of the position of the MMU before formal comments and interventions are made at FERC. The MMU collaborates with SPP staff and market participants when addressing market issues and concerns. While there may be some issues in which it cannot waive, the MMU listens to the concerns of SPP stakeholders and considers their input, explains its views, positions, reasoning and works with SPP staff and market participants to develop workable solutions to improve market outcomes.

7.2 MISSION STATEMENT AND OBJECTIVES

7.2.1 MISSION STATEMENT

The mission of the MMU, as documented in the SPP Open Access Transmission Tariff (OATT), is to “(a) monitor and report on possible abuses of horizontal and vertical market power and gaming in Markets and Services by an Market Participant; and (b) identify market design flaws and recommend any changes in design to improve the operation of Markets and Services for the benefit of consumers and Market Participants’ compliance with market rules.”

The MMU achieves this mission through consistent engagement in stakeholder forums and FERC proceedings, continuous market surveillance and analysis and transparent reporting of market results and analysis in publicly posted reports and discussions.

7.2.2 OBJECTIVES

The MMU works to ensure its functions and activities are implemented fairly and consistently and to protect and foster competition while minimizing interference with open and competitive markets. This includes evaluating existing and proposed market rules, tariff provisions and market design elements. The MMU acts proactively, making recommendations to improve the operation of markets and prevent the exercise of market power in advance rather than punishing offenders afterward.

The MMU has an obligation to report any weaknesses or failures in the market design and market rules, including those not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure. The MMU recommends proposed rules and tariff changes to SPP staff, appropriate FERC staff and other interested entities, like state commissions and market participants. The MMU reviews the performance of the market and provides an annual report on the state of the market with recommendations to improve the efficiency and performance of the market.

7.2.3 INDEPENDENCE

The SPP MMU is independent of SPP, FERC and market participants. The SPP MMU reports to the Oversight Committee, a subset of the SPP board of directors, excluding any SPP management representatives. By reporting directly to the Oversight Committee, the MMU business-related activities are not managed by SPP staff or management. The Oversight Committee conducts detailed oversight of the MMU by approving the MMU's budget and goals and evaluating the MMU's performance on an annual basis. The Oversight Committee's objective is to ensure MMU independence by meeting with the MMU, receiving reports on a quarterly basis, and discussing any concerns that could adversely affect the ability of the MMU to be independent or effectively execute its responsibilities. The vice president of the MMU also meets regularly with a member of the Oversight Committee to keep current on MMU activities.

Independence from market participants allows MMU staff to perform those activities necessary to provide impartial and effective market monitoring. The MMU informs SPP staff and market participants during discussions that the role of the MMU is advisory and non-decisional. Because the MMU is truly independent, it does not vote in stakeholder processes and does not force or intimidate SPP staff or its stakeholders to take a position.

The MMU is also independent of FERC. The MMU monitors FERC proceedings and helps to shape FERC policy by filing comments and communicating with FERC staff where appropriate.

The MMU has documented policies regarding the functions it is and is not allowed to perform as part of its obligations under the SPP OATT. These documents strengthen MMU autonomy, which has been an effective model of independent market monitoring for both SPP and the WEIS markets.

7.3 SCOPE OF RESPONSIBILITIES

The MMU will monitor markets and services by reviewing and analyzing market data and information.

7.3.1 MONITORING AND SURVEILLANCE

The MMU has established tools and processes to monitor for potential gaming and manipulation in the market. The MMU performs its monitoring responsibilities by reviewing and analyzing market data and information. Examples of the type of data and information monitored include resource offer data, virtual bids and offers in the market, export and interchange transactions, commitment and dispatch of resources, market clearing prices and transmission and generator outages. The MMU monitors for potential instances of market manipulation and reports on any possible manipulation in a timely manner. The MMU refers the potential gaming or manipulation activity to the appropriate FERC staff.

7.3.2 MITIGATION

The MMU is charged with protecting the markets from market power abuse. A sound market design can help prevent abuse. Sound design includes development of offer floors and ceilings and automated mitigation measures. Effective mitigation should work to prevent the abuse of market power. The approach used in SPP's markets includes a conduct and impact test, along with a participant-developed and MMU-approved mitigated offer policy. These policies can include opportunity costs where appropriate, including for storage-based hydroelectric generation resources.

Per the tariff, the MMU monitors for potential abuses in the market associated with certain categories of market participant behavior, including "(1) economic withholding; (2) uneconomic production; (3) physical withholding; (4) uneconomic virtual bids and virtual offers; and (5) other items as specified in the tariff." The MMU takes action as necessary, and as defined by the tariff, to apply the appropriate mitigation measures.

Mitigation design should reflect the conditions of each particular market. In the WEIS market, the MMU determined that system wide market power was prevalent due to the structure of the market participants. The MMU, in coordination with SPP staff, recommended a mitigation design to limit the exercise of system wide market power. Given the makeup of the market, the MMU does not see a need for a comparable mechanism. The mitigation construct within Markets+ should reflect the structural conditions within the market footprint.

7.3.3 REPORTING AND TRANSPARENCY

The MMU reports on the performance of the market on an annual, quarterly and monthly basis. The MMU presents the results of these reports to the market participants, SPP staff, SPP board of directors and FERC. In its Annual State of the Market reports, the MMU makes recommendations for enhancements to improve the efficiency and performance of the market.

In addition to routine reporting, the MMU publishes ad hoc reports as needed in response to significant market impacts or changes. Recent reports published by the MMU include a report

on the impact of the February 2021 winter weather event and recommendations to address deficiencies, a paper on virtual transactions in the SPP market and a report on the current funding issues in the congestion hedging market. Earlier reports published by the MMU include a white paper on self-committing resources in the market and a Coordinated Transaction Scheduling (CTS) study. The MMU often includes a special issue in its quarterly reports highlighting interesting market results, significant performance issues or inefficiencies in the market.

In its independent report on the February 2021 winter weather event, the MMU made multiple recommendations for significant enhancements, including resource adequacy and price formation.

7.3.4 SPECIAL PROJECTS

In addition to the responsibilities described, the MMU engages in other efforts, as appropriate, for its obligations under the tariff. One example of this engagement is the MMU participation in the Regional State Committee (RSC) and Organization of MISO States (OMS) efforts to improve seams coordination between SPP and MISO. The RSC AND OMS asked the MMU to participate in the efforts to help these organizations prioritize the scope of work identified for analysis. In addition to aiding in the prioritization efforts, the MMU performed analysis on many of seams issues identified, including publishing a white paper assessing the potential benefits of an interchange optimization process between the SPP and MISO markets.

7.4 MARKET ENGAGEMENT AND RECOMMENDATIONS

The MMU was engaged in the development and implementation of the SPP Integrated Marketplace and the WEIS Market. The MMU continues to monitor these markets and participate in stakeholder groups, providing comments and recommendations where appropriate.

If the MMU discerns any weaknesses or failures in market design and market rules, including the determination that markets and services are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure, the MMU will advise the appropriate organizational group of SPP, the president of SPP, the RSC, appropriate state authorities, FERC staff and relevant market participants³².

7.4.1 INTEGRATED MARKETPLACE

The MMU remains engaged in stakeholder groups and activities and provides comments proposed market changes and enhancements. The MMU provides comments in multiple forums,

³² SPP OATT, Attachment AG Section 6.2

including stakeholder and FERC processes, sometimes supporting the proposed changes and sometimes opposing those changes or identifying a more appropriate enhancement. The MMU has made multiple recommendations in its annual state of the market reports, some which have been addressed and some which are still pending. A subset of those comments and recommendations focusing on effective mitigation, efficient commitment, dispatch and prices are provided below.

7.4.1.1 EFFECTIVE MITIGATION

The MMU has sponsored specific enhancements to improve mitigation, including increasing the accuracy of cost information and reducing the time to update frequently constrained areas.

7.4.1.1.1 MITIGATED STARTUP AND NO-LOAD OFFER MAINTENANCE COSTS

The MMU proposed including major maintenance expenses in the cost-based or mitigated offers. The MMU noted by allowing major maintenance costs to be included in the mitigated offers, market participants would be able to more appropriately reflect the costs of starting and running their resources. The MMU noted that this enhancement would improve overall unit commitment decisions by ensuring the most economic resources were committed.

7.4.1.1.2 ALLOW LOCALLY COMMITTED RESOURCES TO BE MADE WHOLE TO COST PLUS 10%

Under the initial market design, resources committed for local reasons were subject to being mitigated down to cost if the energy offer was 10 percent or higher than the mitigated offer and were only eligible to be made whole to their costs. As a result, market participants were offering just under the 10 percent threshold, in effect mitigating themselves. Excessive or inefficient mitigation is not a goal of the MMU. The MMU proposed capping the energy offer at 10 percent above the mitigated offer when committed to address a local reliability issue in lieu of mitigating the resource down to its cost-based offer. This enhancement allowed resources to submit energy offers at more competitive levels without the fear of being mitigated down to their mitigated offers when committed to address a local reliability issue.

7.4.1.1.3 ACCELERATE FREQUENTLY CONSTRAINED AREA PROCESS

The MMU submitted a market design change to streamline the process needed to implement changes to frequently constrained areas (FCAs) to address market power concerns in a timely manner. The FCA process applies more stringent mitigation thresholds. The initial process resulted in a five to six month lag in effectuating the changes identified by the MMU in the annual FCA study, resources were potentially subject to FCAs that no longer applied and other resources that should have been subject to an FCA where not until the change could be made. The MMU's recommended process changes allowed for resources to have appropriate mitigation thresholds applied much sooner after completion of the analysis.

7.4.1.3.1 Efficient commitment and dispatch

Efficient commitment and dispatch processes lead to more appropriate market outcomes and more accurate price signals. The MMU continues to make recommendations related to improving commitment and dispatch decisions.

7.4.1.4 RAMP CAPABILITY PRODUCT

The MMU recommended the development of a ramp capability product and supported the development through the market design and stakeholder processes. The MMU filed comments supporting the SPP design, noting that the product would provide deliverable ramp capacity to the market, while providing transparent compensation for the procurement of that capacity. The MMU further noted that the product should increase reliability while decreasing the price volatility observed in SPP's real-time markets. The MMU noted its intention to evaluate the method being used for setting the ramp scarcity price curves, which could cause ramp scarcity to be too low and under procure ramp and whether the shape of the demand curve needed to be adjusted.

7.4.1.5 UNCERTAINTY PRODUCT

The MMU recommended the development of an uncertainty product and supported the development through the stakeholder-driven design process. The MMU filed comments supporting the SPP design, noting that intent of the uncertainty reserve product is to improve reliability, price formation and price transparency while decreasing price volatility, make-whole payments and the impacts of out-of-market actions taken to preserve reliability. In its comments to FERC, in which the MMU urged the Commission accept SPP's filing, the MMU also noted two areas for potential future enhancements. These include the potential need to address resources under recovery of costs due to clearing uncertainty reserve amounts less than their minimum operating limits and evaluating the appropriateness of the shape of the demand curve.

7.4.1.6 NDVER TO DVER CONVERSION

The MMU recommended requiring non-dispatchable variable energy resources (NDEVRs) convert to dispatchable variable energy resources (DVERs). The MMU made the recommendation to address inefficiencies caused by NDVERs, specifically the unexpected price volatility related to price-chasing behavior and uneconomic production. The MMU supported SPP staff and market participant efforts to implement the tariff changes need for requiring the conversions. The final SPP proposal, which was included in the tariff filing, included exempting certain resources and extending the conversion timeline. While these changes were not the MMU preferred method, the MMU supported the filing because it agreed the exemptions were limited and reasonable, and the timeline was sufficient.

7.4.1.7 UNDER SCHEDULING OF VARIABLE ENERGY RESOURCES

The MMU made recommendations to address the systematic under scheduling of wind resources in the day-ahead market. The MMU noted that the under scheduling of these forecasted resources can contribute to distorted price signals, suppressing real-time prices and affecting revenue adequacy for all resources. The MMU identified potential enhancements to address these inefficiencies, including incentivizing more variable energy resource and virtual energy participation in the day-ahead market and allocating measurable costs to the cost causers. This remains an open initiative in the SPP initiative roadmap process.

7.4.1.8 SELF-COMMITTED RESOURCES IN THE MARKET

The MMU continues to recommend that SPP staff and market participants address the inefficiency caused by resources self-committing in the market. The MMU notes that it is important to minimize the need to self-commit resources to realize the full benefits of the market. Analysis performed by the MMU confirmed that long lead-time and long run-time resources are often self-committed and contribute to depressing prices in the SPP market. The current market structure is limited in its ability to commit these resources, and market participants often commit them during uneconomic periods. The MMU has continued to recommend that SPP staff and its stakeholders explore and develop ways to reduce the incidence of self-commitment of resources outside of the market solution, including considering adding an additional day to the optimization process in order to better balance forecast accuracy with the ability to commit long lead time and high startup cost resources.

7.4.1.8.1 Price formation

Price formation is the economic basis of incentivizing both short-term operational and long-term investment decisions. The MMU monitors for and makes recommendations regarding areas of the market where prices are not providing the appropriate signals needed to make these decisions. The MMU provided comments in FERC proceedings to address the need for appropriate price formation when considering future enhancements needed to ensure proper transmission and generation is in place to reliably and efficiently meet the needs of the market and ensure just and reasonable rates for ratepayers.

7.4.1.9 IMPROVING PRICE FORMATION DURING EMERGENCY EVENTS

The MMU made recommendations aligned at setting appropriate prices during emergency events. In its recommendations, the MMU noted that when prices are actually signaling an emergency event, market participants can take actions to address the underlying emergency condition, like increasing imports. Accurate prices provide proper signals for investment in new generation or demand response resources to deal with and avoid future emergencies. Appropriate price formation provides an important signal for generators planning maintenance as they will want to minimize outages during periods of high prices.

7.4.1.10 IMPROVING PRICE FORMATION DURING SCARCITY EVENTS

The MMU made recommendations aligned at setting accurate prices during scarcity events. The use of violation relaxation limits (VRLs) during scarcity events may dilute or eliminate the scarcity price effects. Relaxing the spinning reserve requirement instead of clearing the requirement from a graduated demand curve, undervalues spinning reserves when there is competition between products and does not provide a price signal that ensures generator availability. The MMU continues to recommend SPP staff and stakeholders review price formation during scarcity events and consider the establishment of graduated demand curves that incentivize efficient price formation. In the short term, scarcity prices can ensure resources are performing at their maximum limits and that energy imports are incentivized. Even when no more capacity is physically available and imports are exhausted, improved price formation may not result in more product availability during a scarcity event but will produce a price signal that will incentivize future availability.

7.4.1.11 Improving accuracy and transparency of transmission line ratings

The MMU recognizes the importance of accurate line ratings and the impact that those ratings have on the market and appropriate price formation. The MMU commented in FERC proceedings supporting enhancements to methodologies and processes used for determining transmission line ratings used in both transmission planning and market and operational models. Current line ratings are not always determined using the most transparent and accurate methodologies, relying mostly on static seasonal line ratings that do not sufficiently capture variations in congestion and transfer capability on the transmission system. Enhancements like the use of ambient-adjusted ratings (AARs) and dynamic line ratings (DLRs) can be a more cost-effective way to address congestion than building out transmission. Accurate transfer capability would promote more efficient and transparent markets and just and reasonable wholesale market rates.

7.4.1.12 EVOLVING WHOLESALE MARKETS

The MMU recognizes the challenges that come with ensuring sufficient capabilities to serve load in the future. These challenges include integrating renewables into the market, efficiently addressing increased retirements for fossil fuel resources and ensuring sufficient generation and transmission is available to reliably serve the load. MMU staff are actively engaged in proceedings with FERC and discussions with SPP staff and stakeholders to identify enhancements and solutions to address these issues.

Markets will need to change and evolve to meet the challenges of integrating renewable resources and the MMU is contemplating a new framework of flexibility, dependability, availability, resiliency and quality to help meet those challenges. As the MMU has commented in multiple forums and FERC proceedings, the markets need to evolve to address each of these elements.

7.4.2 WEIS MARKET

The responsibilities and obligations of the MMU under the WEIS Tariff are similar to those of the SPP Integrated Marketplace, including the independence of the MMU from SPP staff and market participants.

The MMU monitors the WEIS market for instances of market power and gaming and market design inefficiencies. The MMU identified the need for enhancements in the WEIS market to address the lack of available ramp in the market and improvements needed in the supply adequacy processes.

The MMU performed a market power study in advance of the approval and implementation of the WEIS market. The study investigated whether, and to what extent, structural market power existed in the proposed WEIS market and included recommendations to enhance the competitiveness and efficiency before market implementation. The market power study identified the need to monitor for system wide market power in the WEIS market. The MMU recommended the addition of a test for system wide market in the mitigation design for the WEIS market.

The MMU argued that the system wide market power mitigation approach would allow market offers to set the price when conditions were competitive and would protect consumers when conditions were not competitive. This approach balances the need to send efficient market price signals with protections from market power abuse. MMU staff worked with SPP staff to include an enhancement to the mitigation design for the WEIS market to mitigate for system wide market power.

7.4.3 COMMUNICATION AND OUTREACH

The MMU places importance on engagement with state and federal regulatory entities. The MMU performs outreach on a continuous basis with FERC staff and state commissions. The MMU provides formal and informal education on SPP markets, including education sessions to the RSC and individual state commissioners to help regulators better understand the issues impacting the SPP markets and MMU's engagement in those initiatives.

The MMU holds regular stakeholder calls to present its annual and quarterly state of the markets reports and allow for questions from participants. The MMU regularly provides monthly updates on the SPP and WEIS markets to SPP and WEIS stakeholder meetings.

The MMU maintains a hotline number and email account that are monitored continuously to address stakeholder concerns. Information received through these forums is kept confidential as defined per the SPP and WEIS tariffs.

7.4.4 SPP MMU ADVANTAGE

The MMU takes a balanced approach to its monitoring obligations, considering the impacts to generation and load, thermal and renewable resources and physical and virtual generation when recommending and commenting on market enhancements. The MMU supports competitive pricing when conditions are competitive and recognizes the need for mitigation process when conditions are not competitive to protect consumers. The MMU recognizes the importance of building strong relationships and being professional and respectful, even when disagreeing on market design and policy enhancements. The MMU is collaborative with the SPP staff and stakeholders, while maintaining absolute independence. The MMU has and will continue to support SPP staff and stakeholder initiatives it agrees with and will not hesitate to recommend changes or disagree when appropriate. However, in either case, the MMU will take time to listen to other positions and to explain its views and positions.

8.0 STAKEHOLDER RELATIONS

8.1 TRAINING

Stakeholders consistently rank training services as one of SPP's most valuable services. The Stakeholder Training team's Markets+ training program provides prospective market participants learning opportunities to become confident and effective participants in this energy market.

The table below describes training offerings that will be available to Markets+ participants leading up to and after implementation.

NAME	DESCRIPTION	TIMEFRAME	TYPE	TARGET AUDIENCE
Introduction to Markets+	This course provides an overview of the fundamental concepts for operating and participating in an energy market.	TBD	TBD: Virtual Instructor-led Training (VILT) or Classroom Instructor-led	Personnel interested in understanding Market+ concepts
Markets+ Fundamentals	This course or series of courses will detail the specific functions and features of market operations that ensure	Three months before market trials	Instructor-led course to be hosted in a central location	Personnel tasked with performing or supporting market activities.

	effective participation in SPP's Markets+ program.			
Ad hoc, hot-topic training	These courses will cover specific topics and will be determined based on stakeholder need and/or test results from market trials.	From the start of market trials through parallel operations	VILT or performance support material	Market-support staff
Post Go-Live Training	SPP Stakeholder training provides on-going education post go-live based on market enhancements, NERC/FERC orders, and stakeholder identified needs			

8.2 STAKEHOLDER RELATIONS

In short, the stakeholder relations group is the single point of contact to assist market participants navigate SPP for assistance with onboarding, ongoing business support and technical support facilitation. Onboarding includes the coordination of contractual documentation submission, commercial modeling, ICCP setup, testing, and introduction into the production model as a participant. The second service is the ongoing business support of participants. This includes outreach efforts associated with impacting projects, coordination of multi-team issues, and outreach for awareness of SPP initiatives that change participant business processes. Lastly is the technical support facilitation through the request management system (RMS). This includes requests for system access, the reporting of system issues, and technical questions. Whatever your needs, the stakeholder relations team is here to make your interactions with SPP a success.

9.0 IMPLEMENTATION

SPP introduced the concept of Markets+ to stakeholders in late 2021. Following two initial webinars, SPP issued a survey to gauge potential participants' and stakeholders' level of interest, willingness to commit resources, prioritization of design elements and sense of urgency to launch the market. Based on those results, SPP formed three design teams to address four of the eight proposed design elements: Governance,) transmission availability and market products/price formation. Consistent with SPP best practices, volunteers were selected to serve as stakeholder leads to be supported by SPP staff.

Each design team established its own meeting schedule, objectives and dashboards, which resulted in SPP hosting nearly 50 webinars (some jointly held). In addition, all potential

participants and stakeholders met virtually on a monthly basis for development update webinars. SPP hosted four in-person, two-day meetings in Phoenix, Denver and Portland for general session discussions and breakout sessions for different design teams.

Through the course of the numerous stakeholder meetings, the remaining four design elements were addressed: Congestion rents and peer-to-peer seams were absorbed by the Market Products and Price Formation Design Team, while the market monitoring and greenhouse gas tracking/accounting issues took their own tracks.

Each design team issued draft documents for review and written comment over the past few months. Stakeholder engagement has been strong, with high participation in Markets+ webinars and in-person meetings (two met capacity limits) and broad engagement in submitting written comments and other feedback.

The final service offering contemplates a two-phase process for the continuing development of Markets+. In phase one, potential participants and stakeholders will financially commit to design the market protocols, tariff and governing documents. Phase two – implementation begins upon Federal Energy Regulatory Commission (FERC) approval. In this phase, SPP will acquire necessary software and hardware while participating entities fully commit to fund and are integrated into the system.

9.1 PURPOSE

The purpose of phase one is to facilitate the processes for potential participants and stakeholders to develop the detailed market protocols, tariff and governing documents. SPP has committed to leveraging components of the governance framework to create stakeholder processes, facilitated by SPP staff, which provide structure and voting mechanisms to assist in developing consensus for various proposals while maintaining a schedule that allows all interested parties to reach timeline goals for ultimate integration and implementation.

9.2 SCOPE OF ACTIVITIES

- Market design, including detailed market protocols
- Transmission availability design
- Governance design and partial implementation
- External outreach, including utility commissions, governors' offices, state energy offices, potential participants, stakeholders and other interested parties
- Coordination with existing reliability coordinator and balancing authority operations
- Coordination with Western Electric Coordinating Council standards

- Assessment of interoperability with the Western Resource Adequacy Program and other resource adequacy programs
- Stakeholder support and training

9.3 TASKS

- Coordinate with western groups and agencies to ensure coordination and interoperability between the market and other programs and services.
- Revisit the design elements of market design and transmission availability design.
- Perform necessary analysis to illustrate the feasibility and as proof of concept for design elements where appropriate.
- Hire and train the necessary staff to support phase one – funded investigation of the Markets+ initiative.
- Facilitate stakeholder meetings, including providing meeting support (virtual and in-person) and assisting in material development.
- Provide administrative support, including posting meeting materials and general assistance.

9.4 DELIVERABLES

- Allow potential participants and stakeholders the opportunity to provide substantive comments on all draft governing documents, market protocols, tariff, operating criteria or business practices.
- Facilitate the stakeholder process to assist potential participants and stakeholders reach sufficient consensus to develop a tariff and associated documents for the FERC filing in a reasonable timeline.
- Establish business practices and possible operating criteria for:
 - Transmission
 - Balancing authority coordination
 - RSG interaction
- Prepare and file a tariff and associated documents focusing on markets and transmission recovery mechanisms within settlements.

- Develop governing documents, including charters for components of the governance framework (such as the Markets+ Participants Executive Committee, the Markets+ State Committee and any standing working groups).
- Provide SPP staff support for all stakeholder groups and task forces.

9.5 TIMELINE AND BUDGET

SPP will facilitate the stakeholder process to build consensus on proposals. Potential participants, stakeholders and SPP have a shared responsibility to maintain a reasonable schedule to complete phase one. SPP believes it will take 21 months to develop and prepare the package to be filed at FERC.

The phase one budget is comprised of personnel costs, technical and legal, outside legal and consulting fees and travel/meeting expense. SPP offers this service for execution of phase one for a fixed price of \$9.7 million with a 21-month implementation schedule. The 21-month schedule was developed based on the complexities of the market design and the expected highly engaged stakeholder process necessary to gain desired consensus. Also built into the schedule is the development of the filing letter, supporting analysis and expert testimony.

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 expects some interventions and protests to the filing, and this continued funding will provide adequate resources and support to defend the proposal and receive final FERC approval.

10.0 CONCLUSION

This document sets forth a proposal for SPP's development and implementation of its proposed Markets+ service. The governance and design principles described here are based on the feedback SPP received directly from the western utilities with whom it hopes to partner in the interest of enhancing electricity reliability and affordability in the Western Interconnection. With their input in mind, and drawing on its own experience facilitating mutually beneficial solutions for diverse stakeholders and designing and administering markets, SPP has crafted a market offering that stands to modernize and enhance the way the western grid is operated.

If your organization is interested in working with SPP to develop Markets+ or participating in the stakeholder groups that will govern the market and oversee its continued evolution, contact SPP's stakeholder relations department at stakeholderrelations@spp.org or [submit a request using our Request Management System](#) and a representative will contact you to discuss your needs and options.