Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville's decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,[1] including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest[2] from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.[3] See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams

Bonneville's statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

[1] In this Policy, the "Pacific Northwest" or "region" has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).

[2] Bonneville Power Administration, BPA Facts (Sept. 2024), *available at* https://www.bpa.gov/about/newsroom/fact-sheets.

[3] *Id.*; *see also* Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) ("The White Book"), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.[4] The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)[5] that are individually responsible for ensuring the reliable operation of the electric grid.[6] The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.[7] WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).[8] Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).[9] RTOs and ISOs manage about 60% of the U.S. electric power supply[10] and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.[11] All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

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[4] For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* https://www.ferc.gov/electric-power-markets.

[5] A BAA is defined as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Id.*

[6] BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* https://www.nerc.com) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see* WECC, *available at* https://www.wecc.org).

[7] WECC, About WECC, *available at* https://www.wecc.org/about/about-wecc.

[8] FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier "power pool" concept. Several groups of transmission owners then formed ISOs, some from existing power pools Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

[9] In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

[10] U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20marketers%20and%20energy%20traders.

[11] An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* https://energyknowledgebase.com/topics/ferc-order-2000.asp.

(LMP)[12] to create an "economic dispatch."[13] Section 1234 of the Energy Policy Act of 2005 defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[14]

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.[15] Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.[16]

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.[17] CAISO's overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[18] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA's boundaries have enough generation in their operating plan to satisfy the load and obligations for that

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[12] *See* SPP Markets+ Tariff, Attach. A § 3.2, *available at* https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf ("The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)"). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), *available at* https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

[13] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

[14] 42 U.S.C. § 16432.

[15] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), *available at* https://www.westerneim.com/Pages/About/default.aspx.

[16] *See* CAISO, How the Markets Work (2025), *available at* https://www.westerneim.com/Pages/About/HowItWorks.aspx.

[17] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025). *available at* https://www.westerneim.com/Pages/About/default.aspx.

[18] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.

market participant and BA.[19] The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.[20] As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.[21]

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,[22] and SPP began development of Markets+ in 2022.[23,24] A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.[25] Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

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[19] *See* SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019)*, available at* https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.
[20] *See* SPP, Western Energy Imbalance Service Market (2025), *available at* https://www.spp.org/western-services/weis/.
[21] SPP, Annual Report 2022 at 4, *available at* https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.
[22] *See* CAISO, Initiative: Extended day-ahead market, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.
[23] *See* SPP, Markets+, *available at* https://www.spp.org/western-services/marketsplus/.
[24] SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.
[25] FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* https://www.ferc.gov/OPP/western-markets-explainer.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.[26] The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilaterial world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

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[26] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

that relieves a transmission constraint).[27] This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.[28] According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.[29]

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED[30] accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.[31] "Unit commitment" determines the optimal

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[27] *See* Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), *available at* https://woodsinstitute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

[28] *See* Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

[29] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

[30] As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

[31] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

combination of resources to bring online from those that are available for some or all of the operating day.[32] "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.[33] To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.[34] These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.[35] Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

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[32] CAISO, Technical Bulleting 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.
[33] *Id.* § 3.
[34] Referred to as "Reliability Unit Commitment" in Markets+ and "Residual Unit Commitment" in EDAM.
[35] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.[36]

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[37] (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

[36] *See* Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[37] 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville's comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville's continued decision process • Evaluation of market governance developments • Bonneville's supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville's day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville's evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville's participation is supported by a sound business rationale.

- Strategy – Bonneville's participation is consistent with Bonneville's 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville's statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville's customers is one of the most important aspects of Bonneville's various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources' availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough "steel in the ground" (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)[38] to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

[38] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.[39] The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops[40] exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract[41] that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.[42] Bonneville markets power from the federal hydropower system, Columbia Generating station,

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[39] Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.

[40] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[41] Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[42] Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf (full comments available at https://publiccomments.bpa.gov/CommentList.aspx?ID=421); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.[43] These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

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at https://publiccomments.bpa.gov/CommentList.aspx?ID=480); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market).

[43] Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville's Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25[44] BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

[44] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.[45] The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

[45] For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.[46] Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of $1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded $100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

[46] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.[47]

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a "net cost," which indicated whether the WMEG member should expect a cost or benefit. Again, a positive "net cost" indicated cost to the WMEG member because of day-ahead market participation, and a negative "net cost" indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3's Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)[48]

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

[47] For results, see Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (*see* Workshops, Oct. 23, 2023, WMEG Materials).
[48] Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), *available at* http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3._E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_Final.pdf.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue[49] (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

[49] The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.[50] Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as "Net Cost without Wheeling" for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a "business as usual" (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

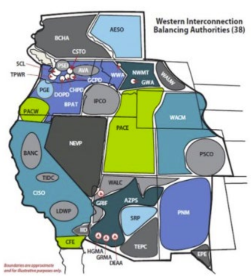
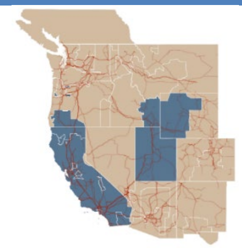
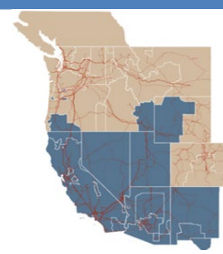
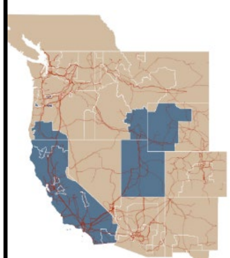
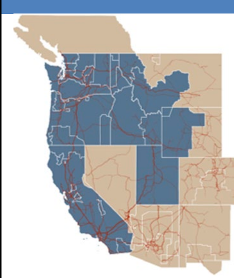
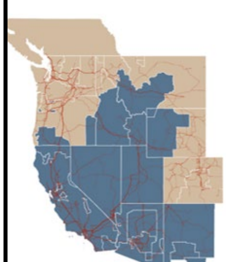
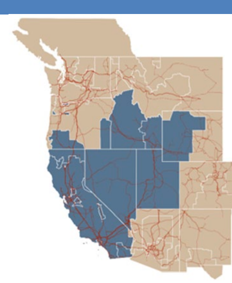
1) The BAA participates in EDAM,

2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

[50] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

Business-as-Usual		**Main Split**	
	This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage		PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
EDAM Bookend		**Alternative Split 1**	
	All US WECC in EDAM; British Columbia Hydro only in Markets+		PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
Markets+ Bookend		**Alternative Split 2**	
	PAC, CAISO, Los Angeles Department of Water & Power. Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)		PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
Alternative Split 3		**Alternative Split 4**	
	PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+		PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville's initial WMEG results are available on Bonneville's website.[51]

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	**Footprint**									
2		**Cost/Benefit Category**	**BAU (2026)**	**EDAM Bookend (2026)**	**Main Split (2026)**	**Markets Bookend (2026)**	**Alt Split 1 (2026)**	**Alt Split 2 (2026)**	**Alt Split 3 (2026)**	**Alt Split 4 (2026)**
3	**Category Value**	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		**Net Costs w/o Wheel**	**-339**	**-475**	**-369**	**-349**	**-359**	**-451**	**-233**	**-277**
9	**Δ Category vs. BAU**	Δ Load Cost		23	3	-19	-2	61	-81	-60
10		Δ Gen Revenue		-149	-29	12	-19	-174	189	121
11		Δ Congestion Revenue		-10	-3	-3	2	1	-1	2
12		Δ GhG Revenue		0	-1	-1	-1	0	-1	-1
13		**Δ Net Cost w/o Wheel**		**-136**	**-30**	**-10**	**-19**	**-112**	**107**	**62**

Green = Benefit Greater than BAU **Red = Increased Cost from BAU**

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,[52] the reduction in projected benefits relative to BAU is driven by generation revenues declining[53] more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville's Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville's WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville's PCM results are

[51] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[52] Alt Split 3 Load Cost reduced by $81m as shown in cell I9; Alt Split 4 Load Cost reduced by $60m as shown in cell J9.

[53] Alt Split 3 Gen Rev declines by $189m as shown in cell I10; Alt Split 4 Gen Rev declines by $121m as shown in cell J10.

available on Bonneville's website.[54]

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the "generation revenue" category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.[55]

5.1.1.4.1. Supplemental Analysis Tasks

1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

1) Market Interactions with WRAP | Understanding the potential difference in ability of either market's rules & practices to enable realization of RA benefits.

2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

[54] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[55] *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

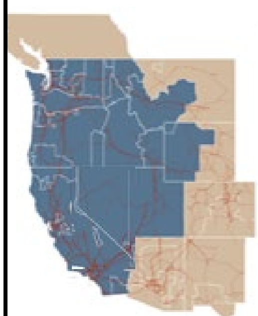
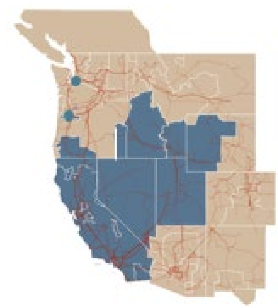
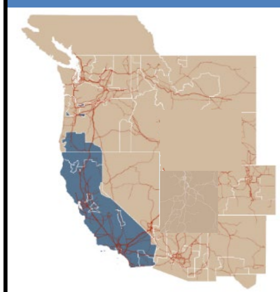
Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	 **EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***
Non-CA Westwide Markets+	
 **EDAM:** California LSE's Only **Markets+:** Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results[56]

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

Supplemental Analysis

	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)	T2 | Alt Split 4A M2M (2026)	T2 | Alt Split 4A M2M2 (2026)	T2 | Alt Split 4A M2M3 (2026)	T2 | Main Split M2M (2026)	T2 | Main Split M2M2 (2026)	T2 | Main Split M2M3 (2026)	T3 | BAU Low Water (2026)	T3 | BAU Low Water & Stressesd Loads (2026)	T3 | Alt Split 4A Low Hydro (2026)	T3 | Alt Split 4a Low Hydro & Stressed Loads (2026)	T3 | EDAM Bookend Low Water (2026)	T3 | EDAM Bookend Low Water & Stressed Loads (2026)	T4 | Alt Split 4A BPA EIM ONLY (2026)	T4 | Alt Split 4A BPA EIM ONLY Low Hydro Stress Load (2026)	T4 | EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 | Alt Split 4A Straw (2026)	T5 | Hypothetical New Additional TX (2026)	T10 | Non-CA WestWide M+ (2026)	T11 | Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs	921	739	818	874	910	961	981	983	1104	1132	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1182	-1156
	Congestion Rev	-50	-65	-59	-56	-57	-52	-54	-57	-30	-30	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GhG Rev	0	0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Net Cost w/o Wheel	**-138**	**-30**	**-98**	**-148**	**-182**	**-192**	**-208**	**-222**	**4**	**15**	**16**	**26**	**-50**	**-42**	**-160**	**5**	**14**	**-61**	**-123**	**-207**	**-195**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost		-182	-103	-47	-11	40	60	62	183	211	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU | Generation Rev		305	153	43	-26	-91	-125	-139	-61	-78	108	73	-45	-62	11	-63	36	226	163	-42	-15
	Δ BAU | Congestion Rev		-15	-9	-6	-7	-2	-4	-7	20	20	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU | GhG Rev		0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Δ BAU | Net Cost w/o Wheel		**108**	**41**	**-10**	**-44**	**-54**	**-69**	**-84**	**142**	**153**	**154**	**164**	**89**	**96**	**-22**	**143**	**152**	**78**	**15**	**-69**	**-57**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	182		79	136	171	222	242	245	366	393	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A | Gen Rev	-305		-152	-262	-331	-397	-430	-445	-366	-384	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A | Congestion Rev	15		6	9	8	13	11	8	35	35	26	26	26	27	-4	34	34	7	-23	19	21
	Δ Alt 4A | GhG Rev	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Whee	**-108**		**-67**	**-118**	**-152**	**-161**	**-177**	**-192**	**35**	**45**	**47**	**56**	**-19**	**-12**	**-129**	**36**	**44**	**-30**	**-92**	**-177**	**-165**

Green = Benefit Greater than anchor point Red = Increased Cost than anchor point

**Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[56] During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the "Generation Revenue" category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category				Declining Hurdle Rates		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results[57]

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

[57] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

Figure 2 | E3 PCM results

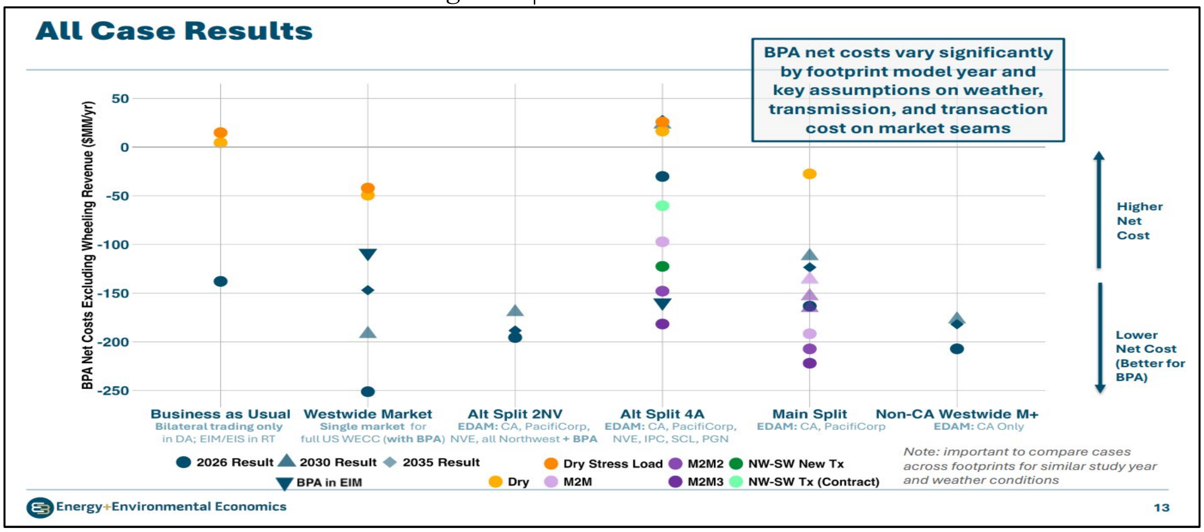


***Figure 2 Takeaway*:** Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

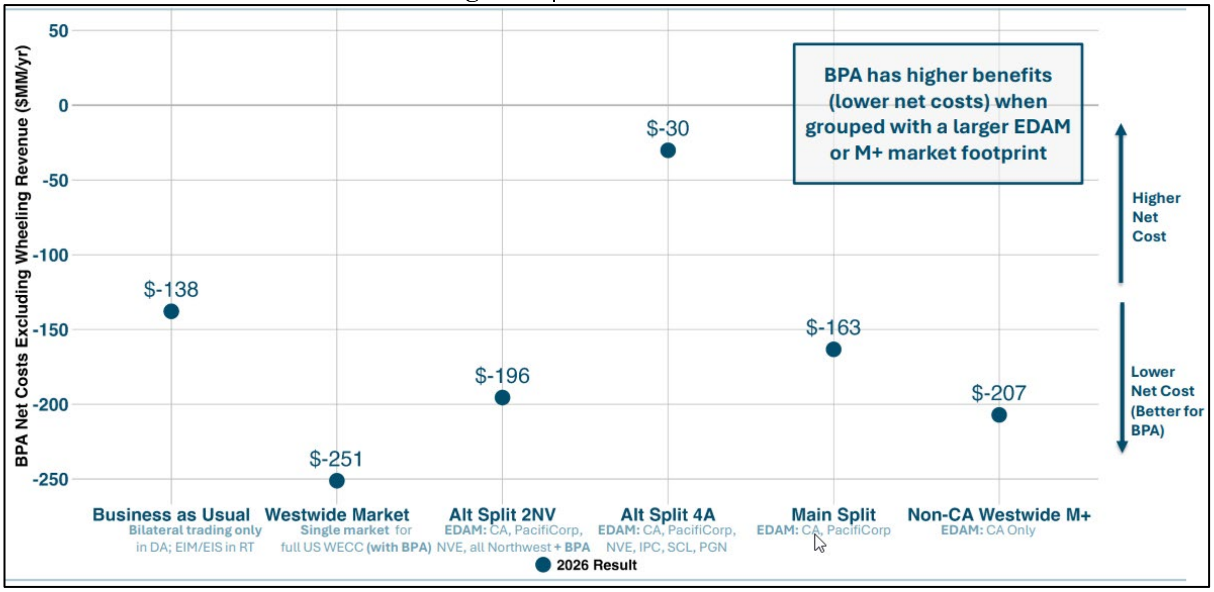


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-30**
9			
10	Δ BAU | Load Cost		-182
11	Δ BAU | Generation Rev		305
12	Δ BAU | Congestion Rev		-15
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**108**

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1		Supplemental	
2	Cost/Benefit Category	BAU (2026)	T11 | Alt Split 2NV (2026)
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-195**
9			
10	Δ BAU | Load Cost		-48
11	Δ BAU | Generation Rev		-15
12	Δ BAU | Congestion Rev		6
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**-57**

***Figure 3 Takeaway*: Footprint is a primary driver of results.**

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by $182 million (see cell R10), but generation revenues go down by more ($305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A ($48 million, see cell AK10), but an increase to generation revenue ($15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville in EDAM.

Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of $30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly $200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly $60 million better. Examining the categorical differences between cases shows that $48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from $251 million to $109 million. Conversely, Alt Split 4A sees an increase in benefit from $30 million to $160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario

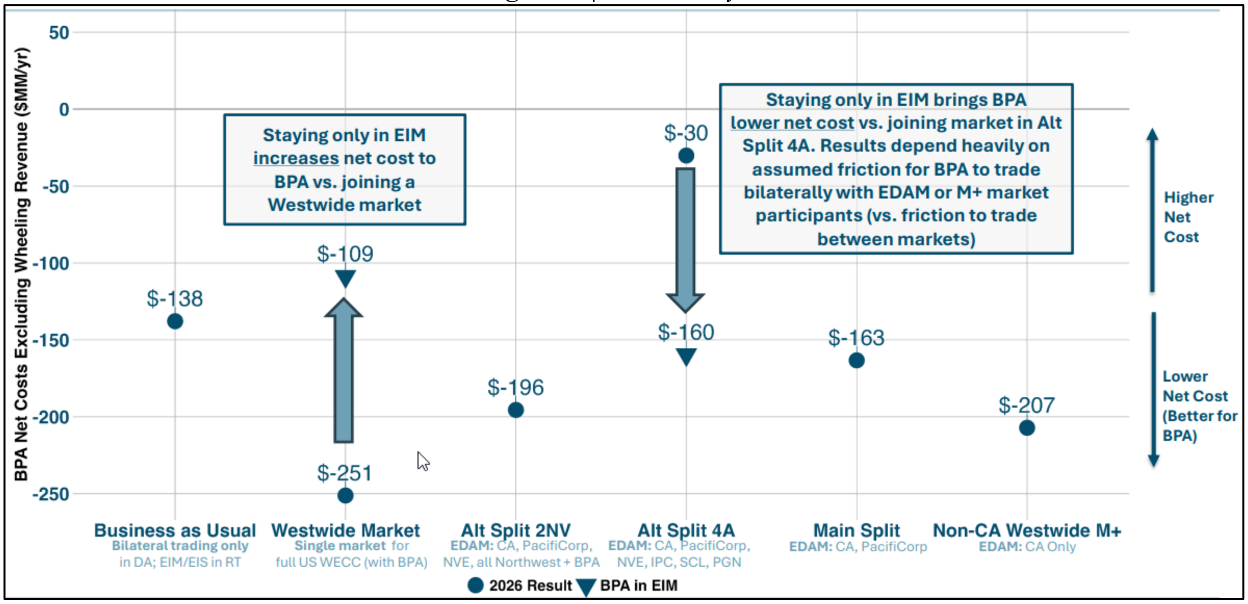


***Figure 4 Takeaway*: WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.**

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

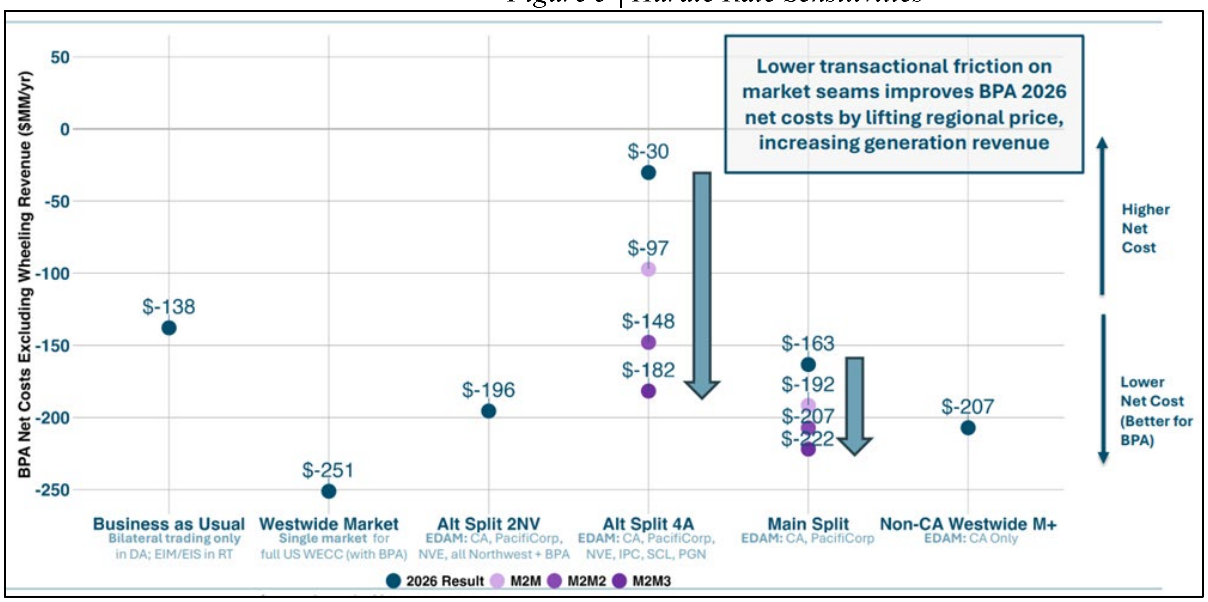
As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	**Supplemental Analysis**					
	M2M		**M2M2**		**M2M3**	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	**DA**	**Weighted Average OATT +$6 adder**	**DA**	**Weighted Average OATT + $3 adder**	**DA**	**50% of Weighted Average OATT + $3 adder**
	M2M DA = $10.50/MWh		**M2M2 DA = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	
	RT	**Weighted Average OATT + $3 adder**	**RT**	**Weighted Average OATT + $3 adder**	**RT**	**50% of Weighted Average OATT + $3 adder**
$14.50 /MWh in DA & RT	**M2M RT = $7.50/MWh**		**M2M2 RT = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	

**** Adder encompasses value for Friction & Congestion Risk***

Figure 5 | Hurdle Rate Sensitivities



<u>***Figure 5 Take-away*****: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.**</u>

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

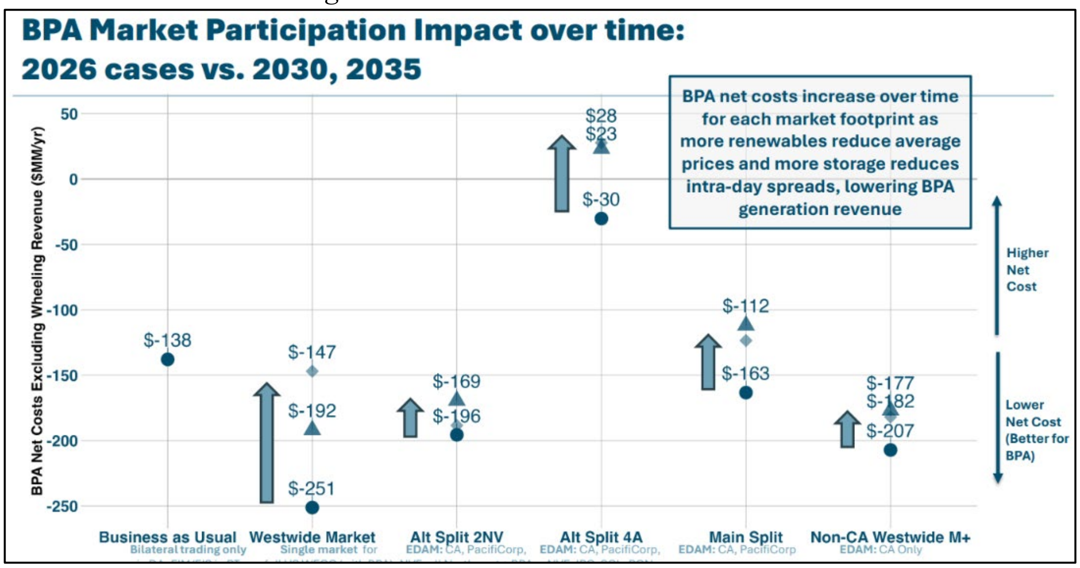


***Figure 6 Takeaway*: Changing regional resource mix may result in declining benefits over time.**

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[58] and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[59] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[60] and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

[58] Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.
[59] Power Revenue Requirement Study - BP-26-E-BPA-02.
[60] Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.[61]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[62] This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.[63]

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.[64] Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

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[61] Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.

[62] BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

[63] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue). Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

[64] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.[65] This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

[65] See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.[66,67] This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.[68] Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

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[66] *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").
[67] *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).
[68] For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from $20 million to $200 million over time.[69] Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.[70] The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.[71] The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.[72]

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

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[69] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.

[70] SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).

[71] CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).

[72] For example, for potential wheeling revenue shortfalls "the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate." *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.[73] CAISO estimates the standard fee to be $1.2 million for each BAA that elects to join EDAM.[74] Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.[75] CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between $2.5 million and $3 million, and the implementation time frame to be between eighteen and twenty-four months.[76]

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately $26.8 million.[77] The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate $29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between $13 and $15 million annually.

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[73] CAISO EDAM Filing, Transmittal Letter at 105-07.
[74] CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[75] CAISO EDAM Filing, Transmittal Letter at 105.
[76] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[77] *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator ($M)

Estimated Fees for Bonneville	**On-going Participation Fee (Paid to MO)***	**One-time Implementation Fee (Paid to MO)***
EDAM	~$29M /year	~$3M
Markets+	~$15M /year	~$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	**Non-Labor**	**Incremental Labor**	**Total Cost (Non-Labor + Incremental Labor)**
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

[78] CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville's existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP's existing systems and processes, which are different than CAISO's and will require system modifications to enable Bonneville's market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville's Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville's Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as "the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders" and that "decision-making and stakeholder engagement occurs in a transparent and inclusive manner."[79] Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville's ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.[80] Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market's design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

[79] Section 4.1.6 above.

[80] *See, e.g.*, Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), *available at* https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[81] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.[82] While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,[83] which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).[84] MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

[81] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.
[82] Cal. Pub. Utils. Code § 345.5 (2025).
[83] *See* Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), *available at* https://www.westernenergyboard.org/wwgpi/.
[84] SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether 5B 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.[85] All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.[86] WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.[87] For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.[88] While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

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[85] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

[86] SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).

[87] Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), *available at* https://www.westernpowerpool.org/news/wrap-area-map.

[88] Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), *available at* https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.[89]

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.[90]

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markest+.[91] As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,[92] the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation[93] issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

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[89] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

[90] SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

[91] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

[92] WECC, 2024 State of the Interconnection (Sept. 2024), *available at* https://feature.wecc.org/soti/index.html.

[93] For more information see FERC, Energy Price Formation (June 17, 2020), *available at* https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.[94] Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.[95] The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

[94] For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.
[95] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.[96] Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME[97] effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals[98]. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders[99]. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,[100] scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

[96] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.
[97] See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.
[98] *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.
[99] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.
[100] *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.[101] These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.[102] Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.[103] The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

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[101] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

[102] SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

[103] The CAISO EDAM tariff provides:

> **Transmission Not Available in the Day-Ahead Market**. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)[104] in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents[105] are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at $25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers $35/MW. The load will pay $35/MW rather than $25/MW because its incremental MWs are served by the other resource offering $35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.[106] The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

n most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.[107] Transfer revenue is

[104] Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

[105] Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

[106] To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

[107] *See* CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.[108] The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.[109] An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.[110] The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.[111] Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."[112] In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."[113] While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.[114] Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

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[108] *See id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.
[109] *See id.*
[110] *See id.* § 33.18.4 (CAISO Transmission at EDAM Interties).
[111] *PacifiCorp*, FERC Docket No. ER-25-951-000.
[112] *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf.
[113] *Id.* (parentheticals omitted).
[114] *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+.[115]

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[116] However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff.[117] In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate[118]. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs.[119]

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

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[115] *See* SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[116] *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[117] *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[118] This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[119] SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.[120] In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

[120] *See, e.g.*, CAISO, Average Emissions Rate Report, *available at* https://www.caiso.com/library/average-emissions-rate-reports.

design (for "Type 1A" attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville's Washington customers. Markets+ design allows participants to register resources as "Type 1A" if they have contracts with load in the GHG Pricing Zone.[121] This "Type 1A" treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This "Type 1A" treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington[122] and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as "Type 1A" resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM's design recognizes contractual commitments[123] but not in an equivalent manner to Markets+ Type 1A treatment. EDAM's design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).[124] Thus, EDAM's design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM's market design, paired with the design of Washington's cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville's preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville's power customers in Washington. This could occur because in-state resources[125] always have the GHG adder[126] in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville's

121 *See* SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.
122 Currently, in Bonneville's BAA, only its customers in Washington will have load included in a GHG Pricing area.
123 *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
124 Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. *See* SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.
125 In-state resources are generally resources physically located in the state with the GHG pricing program (*e.g.*, Washington). However, pursuant to Washington's Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. *See* Wash. Rev. Code § 70A.65.010(42)(c).
126 A GHG adder represents the monetary value of an individual resource's emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). *See* CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. Markets+ Baseline "Threshold" Run recognizes Bonneville's load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs

For customers located outside Washington, Markets+ design (the "threshold enhanced floating surplus" approach)[127] gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant's total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant's load obligations. Markets+ uses a baseline run that takes those obligations (the "threshold") into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes[128] and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,[129] there is no in-market mechanism that aligns the participant's load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM's baseline run (the "reference pass")[130] takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will "approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[131] As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant's load obligation.[132]

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage[133] is by assuming the load obligations of all market participants external to the GHG pricing area

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[127] *See* SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.
[128] Email exchange between Bonneville and SPP (on file with author).
[129] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[130] *See* CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[131] See CAISO EDAM Filing, Transmittal Letter at 163-69.
[132] The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.
[133] "Leakage" as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.[134]

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,[135] which limits attribution from resources in a BAA where that BAA is a net importer.[136] However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,[137] about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance[138] in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

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Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11. CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

[134] Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

[135] *See* CAISO EDAM Filing, Tariff § 29.32.1.

[136] The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

[137] Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

[138] The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. *See* CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run[139] and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.[140] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.[141] In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.[142] It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

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[139] The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

[140] *See* SPP, Markets+ GHG Task Force, *available at* https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).

[141] *See* CAISO, Greenhouse Gas Coordination Work Group, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group.

[142] CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size[143] in Bonneville's BAA will be subject to the market tariff and rules,

[143] In the WEIM, Bonneville requires all generators above 3 MW to be modeled. *See* Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.[144] Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.[145] The basic energy settlement equations are described in Section 6.6.[146]

All resources participate, but can self-schedule

In the context of the WEIM, "participating resources" are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and "non-participating resources" are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered "participating" because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for "self-scheduling" which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant[147] Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville's Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

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[144] *See* Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.

[145] SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).

[146] *See also* SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).

[147] Pursuant to the Markets+ Tariff Definitions: "Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC."

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10 hydro resources.[148] The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,[149] Lower Snake,[150] and Lower Columbia[151] areas).[152]

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

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[148] The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.
[149] Aggregation of Grand Coulee and Chief Joseph Dams.
[150] Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.
[151] Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.
[152] For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.[153] There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.[154]

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

[153] Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

[154] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.[155] Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

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[155] *See WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or "INC" capacity is deployed when there is under-generation relative to load and decremental or "DEC" capacity is deployed when there is over-generation relative to load.

Before Bonneville's entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville's own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR[156] is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville's BAA. During times of high river flows, typically in the spring when loads in Bonneville's BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.[157]

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[156] *See* Bonneville Power Administration, Operational Controls for Balancing Reserves, *available at* www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.

[157] *See* Bonneville Power Administration, Oversupply, *available at* www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants[158] will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.[159] Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement[160] for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

[158] *E.g.*, Planned Product customers, independent power producers, etc.
[159] Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.
[160] Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP[161] Service and NITS.[162] PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any another relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

[161] Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf.
[162] Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf.

public workshop 8 on July 18, 2024.[163] Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints[164] (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"[165] their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.[166] Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.[167] Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

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[163] Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf.
[164] Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.
[165] SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).
[166] Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.
[167] SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag. [168] The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day. [169] These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

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[168] E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

[169] Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), *available at* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf.

6.8.2. Transmission Losses

As energy is physically delivered across a transmission system, there is a natural degradation or "loss" that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is "lost" on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the "donation model" of Transmission Rights by Interchange Rights Holders[170] to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid "double-payment," Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville's current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville's tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

[170] Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville's decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act[171] to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.[172] Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville's authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[173] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[174] Bonneville's statutes are unique with repeated focus on the business-related aspects of the agency's authority.

Both Congress and the courts have reaffirmed Bonneville's authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing Bonneville's operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

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[171] 16 U.S.C. § 832a(f).

[172] Bonneville Power Administration, Energy Imbalance Market Policy, Administrator's Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalancemarket/rod-20190926-energy-imbalance-market-policy.pdf; Bonneville Power Administration, Bonneville's decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.

[173] Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).

[174] Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

> of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.[175]

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.[176] Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that "[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act's passage."[177]

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.[178] As stated in the 1995 Business Plan Record of Decision, Bonneville's objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.[179] The market-driven approach is designed to increase the value of Bonneville's business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.[180] By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville's customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities' participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.[181]

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville's authority to market federal power is included in several statutes: the Bonneville Project Act

[175] S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.
[176] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).
[177] *Id*.
[178] Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf.
[179] *Id.* at 1.
[180] *Id.* at 11.
[181] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, "[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."[182] Section 4(b) further explains, "in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted."[183] The Flood Control Act of 1944 similarly states that "[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives."[184] Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, "[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."[185] The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

> The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

[182] 16 U.S.C. § 832c(a).

[183] 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) ("[T]he preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." (citing section 4(b) of the Bonneville Project Act)).

[184] 16 U.S.C. § 825s.

[185] 16 U.S.C § 839c(a)

> and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.[186]

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.[187] The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].[188]

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

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[186] H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

[187] As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers . . . . This is a bill to solve a power allocation problem . . . ." 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

[188] 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.[189] It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).[190]

Importantly, section 5(b) contracts are not a response to "competing or conflicting" requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.[191]

Bonneville's ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.[192] If the Administrator "cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency" he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions. [193]

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.[194]

Additionally, Bonneville's participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council's Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville's continued efforts and the benefits that coordination

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[189] 16 U.S.C. § 839d(b)-(d).
[190] 16 U.S.C. § 839e(a)-(b).
[191] 16 U.S.C. § 838i(b)(6).
[192] 16 U.S.C. § 839c(b)(5).
[193] *Id.*; 16 U.S.C. § 839c(b)(6).
[194] *See* Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937[195] and the Pacific Northwest Consumer Power Preference Act of 1964[196] specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.[197] Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.[198]

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

[195] 16 U.S.C. § 832 *et seq.*
[196] 16 U.S.C. § 837 *et seq.*
[197] WEIM Policy ROD at 62.
[198] *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

> In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.[199]

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

> The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.[200]

Section 6(l)(2) further provides:

> The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.[201]

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.[202] Interchange energy means energy received by one utility system from another, usually in exchange for

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[199] 16 U.S.C. § 832a(b) (emphasis added).
[200] 16 U.S.C. § 839d(l)(1).
[201] 16 U.S.C. § 839d(l)(2).
[202] *See* Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.[203] While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

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[203] *See Cal. Energy Comm'n v. Bonneville Power Admin.,* 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.[204]

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.[205] When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.[206] RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery." [207]

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

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[204] *See* Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . . .").

[205] 42 U.S.C. § 16431.

[206] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

[207] *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law . . . ."[208] Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[209] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[210] Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville's proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, 2) based upon the Administrator's total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.[211]

In a day-ahead market, Bonneville's rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville's rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville's rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator's obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville's governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville's authority to determine the terms and conditions of transmission service.[212] In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

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[208] *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).
[209] 16 U.S.C. § 839e(i).
[210] 16 U.S.C. § 839e(a)(1).
[211] 16 U.S.C. § 839e(a)(2).
[212] 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.[213]

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

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[213] 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found here.

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville's strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC's requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.[214] Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.[215] In eastern RTOs,/ISOs, they are vertically aligned among roles[216] as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

[214] *E.g.*, Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).
[215] *E.g.*, SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.
[216] *I.e.*, RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC Rules of Procedure *(ROP Section 500, 1.4.1)*, all areas *(geographic or electrical)* are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This “market congestion” or “commercial congestion” may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market’s management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities[217] and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

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[217] *E.g.*, BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL[218] and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.[219] Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

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[218] The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.

[219] Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and interties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the "binding" limit. An indication that congestion is occurring is "price separation" between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.[220]

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market's participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

[220] *See* Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.[221] The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

[221] *See* Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.