Department of Energy

Bonneville Power Administration
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EXECUTIVE OFFICE

June 20, 2019

In reply refer to: A-7

RE: EIM Participation

To: Bonneville Power Administration's Stakeholders

The Bonneville Power Administration (Bonneville) has formally launched a public process to determine its future role in the Western Energy Imbalance Market (EIM). The first decision will be whether to sign an Implementation Agreement with the California Independent System Operator (CAISO). I am proposing to sign the agreement in September and move toward joining the EIM in March 2022. To support this proposal, Bonneville prepared a "Proposal for Bonneville to Sign an EIM Implementation Agreement," included as Attachment A to this letter.

Participating in an efficient, organized energy market is one action Bonneville could take in its effort to modernize assets and system operations, a key goal of our 2018-2023 Strategic Plan. Through Bonneville's grid modernization initiative, in a coordinated partnership with the U.S. Army Corps of Engineers and Bureau of Reclamation, we are driving efficiencies to support commercial and operational success while maintaining reliability and meeting our obligations to the region.

Signing the Implementation Agreement would not obligate Bonneville to join the EIM, but it is an important milestone, as it establishes a high-level project plan and schedule for the steps we must take to join the market.

To inform this decision, we have been studying how and under what conditions Bonneville could join the EIM. This package describes our findings, much of which has already been shared through previous stakeholder engagements. It includes the results of a cost-benefit analysis, the draft Implementation Agreement, and the principles that must be met before Bonneville will participate in the market. Bonneville has also provided its perspective on the legal implications of joining the EIM, a roadmap of the process for policy decisions needed to get to a final decision, and analysis of several foundational decisions about how Bonneville will participate in the EIM.

To date, all of the participating EIM entities have reported significant generation dispatch benefits, improved situational awareness, and congestion management on their transmission systems. Bonneville's participation would give power and transmission customers the opportunity to participate in the market with their own generation. Marketers of independent power plants located in the Bonneville balancing authority area would also be eligible to participate in the market.

In 2017, Bonneville staff performed an initial, internal analysis to determine whether there were sufficient benefits for Bonneville to formally explore joining the EIM. Staff's analysis concluded that joining the EIM could provide modest but positive net revenue. Based on this finding, I initiated a formal process to consider whether Bonneville should join the EIM. I directed staff to commission a more exhaustive and precise cost-benefit analysis, consistent with what other utilities have done when considering whether to join the EIM. To perform the cost-benefit analysis, Bonneville contracted with E3, an organization that has performed many similar industry-standard analyses for EIM participants.

The cost-benefit analysis shows Bonneville could earn additional annual power revenues of approximately $29-34 million. There are also significant benefits for transmission reliability and operations due to the improvement in situational awareness, visibility, and congestion management associated with participation in the EIM. This is consistent with the goal of using the transmission system more efficiently.

While the cost-benefit study and other aspects of EIM participation are very encouraging, I realize that joining the EIM has implications for several aspects of Bonneville's operations and business model. There will also be some implications to the services that Bonneville provides its power and transmission customers. That's why we have established a set of principles by which the multiple decisions associated with moving into the market will be measured.

As we approach this significant milestone for Bonneville and the region, I want to emphasize that a well-designed electricity market is built on a strong foundation of resource adequacy, has features that optimize intra-hour energy balancing, and explicitly compensates capacity resources for providing capabilities that are essential for system reliability. While the projected revenues and other benefits of EIM participation are encouraging, the EIM is designed to compensate resources for the real-time energy and ramping capability they provide, which Bonneville views as just one piece of a well-designed electricity market. Additional mechanisms are required to compensate Bonneville for the capacity value of the flexible, carbon-free federal power it chooses to provide.

To complement the EIM, the CAISO should administer a day-ahead product that incents the commitment of additional flexible capability from resources that can be deployed in real-time. I view such a product as an opportunity for Northwest hydro and other dispatchable resources that can quickly ramp up or down to make up for unscheduled changes in load and generation. These valuable capabilities will support the reliability of the western transmission grid as we work to integrate large amounts of additional renewable energy generation. Bonneville has taken an active role in the CAISO's ongoing effort to develop a day-ahead flexible ramping product. Based on dialogue with CAISO leadership, I expect that the CAISO will complete its stakeholder process and implement this product before Bonneville goes live in the EIM.

We are seeking comments on Bonneville's decision to sign the EIM Implementation Agreement and all other aspects of the attached package. Comments are due by the Close of Business on July 22nd. The attached package includes:

- Proposal for Bonneville to Sign an EIM Implementation Agreement (Attachment A) (includes EIM principles, legal authority, business case, decision-making process and schedule, and certain foundational policy proposals);
- Bonneville Power Administration Energy Imbalance Market Benefits Study, Executive Summary of Initial Results, prepared by E3 (Attachment B); and
- Draft Implementation Agreement (Attachment C).

Bonneville will use the input from comments to develop a record of decision planned for release in September. If the decision is to sign the Implementation Agreement, the next steps will include implementation activities and further stakeholder processes for the additional policy development, leading to needed changes to the Tariff and rates in the TC-22 and BP-22 cases. All this activity will build up to Bonneville making a final decision on whether to join the EIM in late 2021.

In closing, I sincerely appreciate the engagement of our federal partners, the U.S. Army Corps of Engineers and Bureau of Reclamation. I also appreciate stakeholders' participation and thoughtful input in this process. Bonneville is only successful when it moves ideas forward through collaborative and transparent processes where all the voices of its customers and other stakeholders are heard and considered. Joining the EIM would be a big step forward for Bonneville. I see this as an opportunity to move Bonneville into the future and ensure we continue to drive the region's economic prosperity and environmental sustainability. Thank you in advance for your constructive feedback on this important initiative.

Sincerely,

Elliot E. Mainzer
Administrator and Chief Executive Officer

Enclosures (as stated)

Attachment A

Proposal for Bonneville to Sign an EIM Implementation Agreement with the CAISO and Move Forward Toward Joining the EIM

Attachment A

Proposal for Bonneville to Sign an EIM Implementation Agreement with the CAISO and Move Forward Toward Joining the EIM

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Attachment A

I. Background

The Bonneville Power Administration (Bonneville) is considering whether to sign an Implementation Agreement, which is a necessary first step to join the California Independent System Operator's (CAISO) Western Energy Imbalance Market (EIM). As part of its decision, Bonneville has prepared this Letter and Policy Proposal document (Proposal) to describe the legal, business, operational, and policy considerations associated with joining the EIM. This Proposal is the culmination of Bonneville's initial findings on these matters. The majority of the content set forth in this Proposal has previously been discussed with stakeholders through monthly public meetings that Bonneville began in July 2018.[1]

As explained in the Administrator's cover letter, the decision to sign the Implementation Agreement will signal Bonneville's intent to join the EIM as long as certain principles are met during implementation and the remaining policy issues are resolved prior to beginning financially binding transactions in the market (go-live) in 2022. The decision to sign the Implementation Agreement is the first of several decisions that need to be made before Bonneville could begin market participation.

The remaining portion of this section describes: (1) the changing energy landscape in the Western United States; (2) what the EIM is and how it operates; and (3) why Bonneville is interested in EIM participation.

a. Changing Energy Landscape in the Western United States

Changes in the Energy Industry

The energy industry is experiencing fundamental changes in structure that continues to directly impact Bonneville's operations and commercial value. These industry-wide changes are driven by the significant expansion of variable energy resources (VERs) output, as well as the need to maximize the utilization of existing transmission capacity prior to embarking on expensive and time-consuming transmission expansion efforts. VERs are getting cheaper to build and operate.[2] Regional public policy makers and end-use consumers are also demanding a cleaner mix of energy resources.[3] Since 2010, generation

[1] For more information on Bonneville's public stakeholder process and materials, please see https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx.
[2] *See* 2018 Annual Technology Baseline, National Renewable Energy Laboratory, *available at* https://atb.nrel.gov/electricity/2018/index.html?t=in.
[3] Washington, Oregon, and California have all passed or are considering legislation to implement zero-carbon.

output from variable energy resources in the West has grown by 150% while generation output from other resource types has been flat or declining.[4]

Long-line transmission is expensive to build, operate, and maintain, and moreover, many people do not want transmission lines in their backyards. In 2017, Bonneville decided to defer its own transmission build option through the South of Allston transmission constraint.[5] This was due in part to costs, local opposition, and the emergence of non-wires options—including the possibility of joining the EIM—that were proving effective at reducing flows through the South of Allston and were helping Bonneville address transmission service requests on that path.[6] While the EIM helps maximize the use of the existing transmission system, additional transmission reinforcements will likely be needed in the future.

For decades, these high-level trends have worked together in other parts of the U.S. to stimulate the adoption and expansion of organized markets. Regional Transmission Organizations (RTOs) are able to increase generation in some areas and simultaneously decrease generation in others—known as re-dispatch—across a broad market footprint to maximize the use of the existing transmission grid, alleviating pressure to build new transmission lines. The same re-dispatch of generation can also reliably and efficiently ease the integration of variable energy resources.

The uncertainty of wind and clouds—which cause VERs to vary moment-to-moment and throughout the day—can be matched with the near instantaneous demand from load by calling on the least cost generator(s) in a larger, diverse geographic area that have the available generation capability to ramp up or down. However, with the exception of the California Independent System Operator (CAISO), the Western U.S. had not been able to formulate a viable region-wide organized market until November 2014, when PacifiCorp and the CAISO initiated the Energy Imbalance Market.

Until that time, the rest of the West had utilized bilateral markets to buy and sell electricity. As zero variable cost energy supply from VERs has increased in the CAISO's organized

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[4] Short-Term Energy Outlook, DOE (May 2019), *available at* http://www.eia.gov/outlooks/steo/.

[5] See*, e.g.*, Bonneville's decision not to build the I-5 Corridor Reinforcement Project, citing the size, local impacts, and increasing costs as reasons to not build the proposed project. Bonneville Power Admin., I-5 Corridor Reinforcement Project Decision Letter (May 17, 2017), *available at* https://www.bpa.gov/Projects/Projects/I-5/Documents/letter_I-5_decision_final_web.pdf.

[6] Bonneville's Non-Wires SOA Pilot Summary Results, slide 4 (Dec. 10, 2018), *available at* https://www.bpa.gov/transmission/CustomerInvolvement/Non-Wire-SOA/Pages/Meetings.aspx. "BPA acquired two years of incremental and decremental capacity and energy (deployed with day-ahead notice) to reduce flows on SOA flowgate during summer peak periods. . . . Non-wires portfolio balances 200 MW of incremental capacity with 200 MW of decremental capacity to provide counter flow." *Id.*

markets, downward pressure has been exerted on energy prices inside the CAISO and this has extended into bilateral markets in the West. At the same time, natural gas prices have fallen as increasingly efficient extraction techniques have emerged. This too has driven electricity prices lower. On the other hand, the need for capability produced by generation resources that are carbon free and flexible has been growing. Bonneville markets federal hydroelectric power (energy and capacity) and anticipates demand for this capacity will continue to increase in the West.

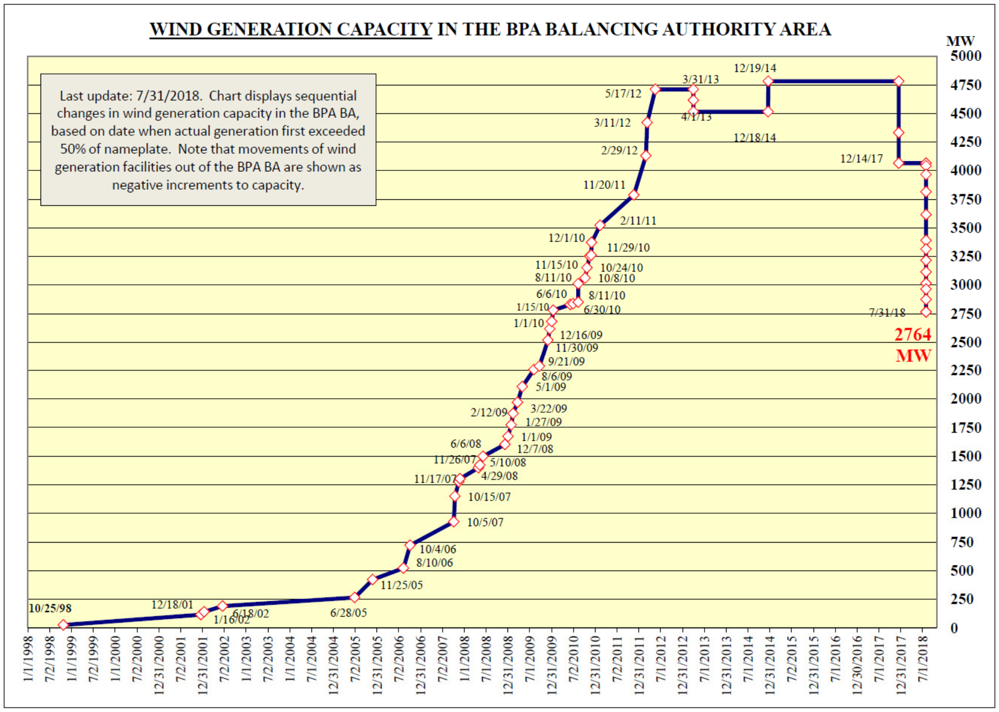
The Effect of the Changing Energy Landscape on Bonneville

Bonneville has been navigating these industry-wide changes. Bonneville has increased sales of long-term firm transmission in the past 10 years, allowing Bonneville to operationally integrate the most diverse set of generating resources into the Federal Columbia River Transmission System (FCRTS) in the history of Bonneville. This is in large part due to thousands of megawatts of renewable generators interconnecting to the FCRTS and purchasing transmission and ancillary services from Bonneville.

On the generation side, Bonneville has enhanced our positioning of the FCRPS to significantly increase its capability to make available the flexible, clean hydropower generation for more granular dispatches to support the variability of VERs. This has resulted in Bonneville selling generation integration services to variable energy resources that help to reliably transmit their variable generation output to loads. However, revenue from generation integration services is now declining as VERs exit the Bonneville balancing authority area in search of lower cost services from non-Bonneville sources.[7]

[7] PacifiCorp, Portland General Electric, Puget Sound Energy, and Avangrid have each electrically removed their variable energy resources from Bonneville's balancing authority area and added them into their own balancing authority areas, thus reducing the amount that they pay to Bonneville for integration services, while continuing to pay Bonneville for transmission service.

Attachment A

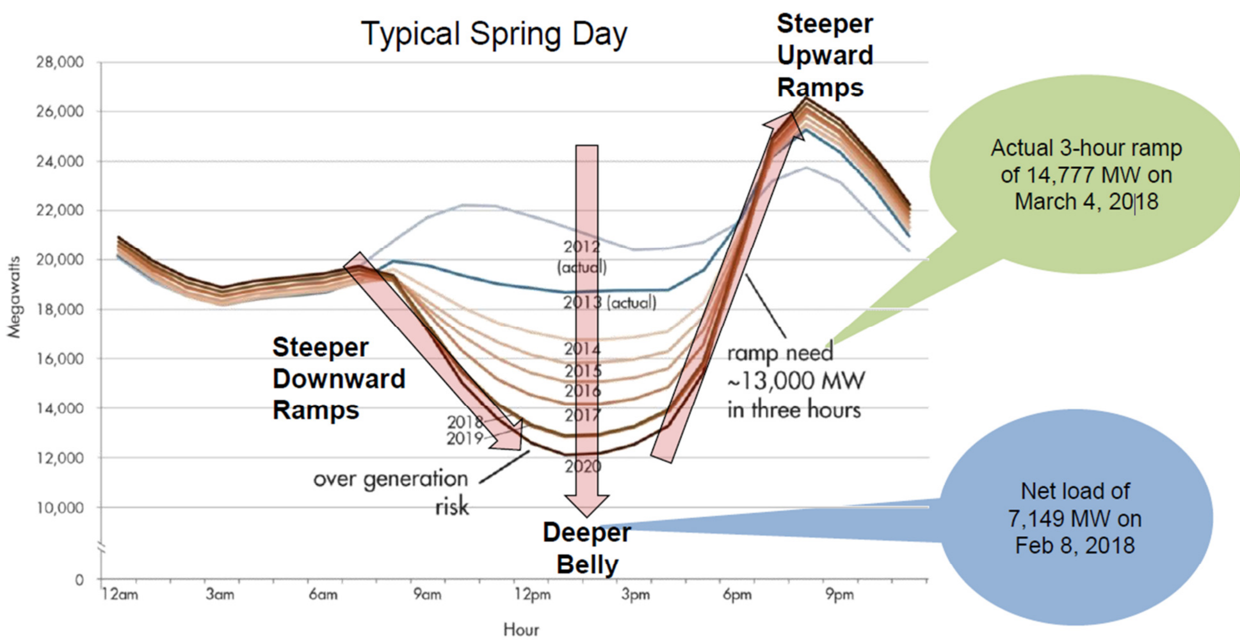


The above graphic illustrates how wind resources in particular were rapidly interconnecting into the Bonneville balancing authority area until 2012 and then subsequently exited in large numbers in 2017 and 2018. While those resources continue to take transmission service from Bonneville, they are now choosing to leave the Bonneville balancing authority area for other opportunities, including the possibility of participating in markets like the EIM.

Bonneville often has more energy supply than it needs to meet preference customer load. Therefore, in most years, Bonneville is a net seller of electricity into bilateral markets. But these markets are now experiencing abundant supplies of VERs generation and generation from low-priced natural gas. As a result, the revenues that Bonneville receives from its surplus sales have been declining. These dynamics—reduced capacity and energy revenues—have exerted upward pressure on Bonneville's power rates, affecting Bonneville's competitiveness in the region.

The CAISO's Response to the Changing Energy Landscape

Similarly, California has experienced significant expansion in VERs, pressure not to build long-line transmission, and low natural gas prices. Arguably, the CAISO's experience with some of these trends is even more pronounced than any other portion of the West.



Since 2012, the CAISO has published this "duck curve."[8] This graphic illustrates how significantly and quickly the expansion of output from VERs, particularly solar, has altered the traditional diurnal nature of its daily load curve. Now the CAISO's net load curve—load minus VER output—is oversupplied in the mid-day hours. These were traditionally the high load hours, and were therefore highly valued on-peak hours for energy sales. This "duck curve" also displays very pronounced morning and evening ramps in the spring that push the CAISO market and its operators to incent more flexible generators to be available in these hours to stabilize the grid as the sun rises and sets. Not only do marginal clearing prices for energy in organized markets like the CAISO contribute to solving this, but the CAISO has also pioneered its real-time Flexible Ramping Product in 2016. This product further compensates generators in its real-time market for the opportunity cost of producing—or not producing—energy in a current market interval so that the same generator can be available to ramp up or down when its ramp capability is needed in a future interval.[9] In other words, Participating Resources[10] are compensated for pre-positioning to generate when needed most.

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[8] Energy Storage and Distributed Energy Resource Phase 4 Issue Paper, CAISO Stakeholder Workshop, CAISO, at 38 (Mar. 18, 2019), *available at* http://www.caiso.com/Documents/Presentation-Energy-Storage-DistributedEnergyResourcesPhase4-Mar18-2019.pdf.

[9] Market Notice: Flexible Ramping Product Deployed and Activated, CAISO (Nov. 1, 2016), *available at* http://www.caiso.com/Documents/FRP-RSI_CPM_CCE2Deployed-Activated.html.

[10] *See* CAISO Tariff § 29.4(d), *available at* http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf. Participating Resources in the EIM must sign a Participating Resource Agreement with the CAISO, submit hourly bids and base schedules to the CAISO, and settle directly with the CAISO.

This chart also shows that additional flexible resources will be necessary to address these morning and evening ramps. To this end, the CAISO's efforts to develop a day-ahead product(s) that incents the commitment to pre-position additional flexible capability from resources in the day-ahead that can be deployed in real-time will help address these ramping challenges. This product(s) would be an opportunity for Bonneville and other Northwest hydro, as well as other dispatchable resources that can quickly ramp up or down to make up for unscheduled changes in load and generation.

Similar to Bonneville, the CAISO has not approved any new long-line transmission recently.[11] This contributes to increasing amounts and duration of transmission congestion inside the CAISO market that can cause locational prices to decrease in some areas and rise in other areas of the CAISO balancing authority area.[12]

California has also experienced low natural gas prices since 2014.[13] This has contributed to low market clearing prices in many intervals, which cause existing and prospective owners of traditional dispatchable resources to not earn enough revenue to recover their capital costs.[14]

The EIM extends the CAISO's access to participating generators outside of its balancing authority area to help it to more efficiently manage the oversupply and daily ramps created by VERs. The CAISO has avoided 810,116 megawatt hours of renewable curtailments

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[11] The 2018-2019 ISO Transmission Plan provided an update on the ongoing transmission projects that were previously approved by the CAISO Board of Governors, as well as approvals for new projects this year. There were no new long line 500kV transmission project approvals greater than 60 miles in length and approximating the $750 million cost of Bonneville's project formerly known as the I-5 Corridor Reinforcement Project. Among previously approved projects costing $50 million or more (see Table 8.1-2) in the 2018-2019 Transmission Plan), there are only two transmission projects that Bonneville might consider to be similarly capital intensive "long line" projects. These are the approximately 60-mile Harry Allen (a substation owned by NV Energy) to Eldorado (a substation owned by Southern California Edison (SCE)) 500kV transmission line project approved in 2014 that is expected to be in-service in 2020 and the 114 mile Delaney (a substation owned by Arizona Public Service) to Colorado River (a substation owned by SCE) 500kV transmission line project that was also approved in 2014 with an expected in-service date in 2021. 2018-2019 Transmission Plan, California Independent System Operator, Mar. 29, 2019, at 469-82, *available at* http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf; 2013-2014 ISO Transmission Plan, CAISO, at 277-95 (July 16, 2014), *available at* http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf; 2013-2014 ISO Transmission Plan, ISO 2013-2014 Transmission Planning Process Supplemental Assessment: Harry Allen-Eldorado 500 kV Transmission Project Economic Need, CAISO, at 2 (Dec. 15, 2014), *available at* http://www.caiso.com/Documents/HarryAllen-EldoradoProjectAnalysisReport_AppendixA.pdf.

[12] *See* 2018 Annual Report on Market Issues and Performance, CAISO DMM, at 11 (May 2019), *available at* http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

[13] *See id.* at 3-4.

[14] *See id.* at 15-17.

because of the EIM.[15] The amount and shape of EIM energy transactions has also deflected some of the pressure from transmission congestion and thermal resource retirements in California, while providing operational enhancements and spreading more than $650 million of gross benefits among all EIM participants.[16]

b. Description of the EIM

In assessing whether Bonneville should join the EIM, it is important to understand the mechanics of how the EIM operates.

Overview

The EIM[17] is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between balancing authority areas (interchange), and load across the market's footprint. It does so while simultaneously ensuring generation and transmission limitations are respected. For balancing authorities in the EIM (EIM Entities), the EIM replaces the provision of imbalance under sections 4 (energy imbalance) and 9 (generator imbalance) provided under the EIM Entities' respective Open Access Transmission Tariffs (Tariff). In joining the market, EIM Entities revise the imbalance service provisions of their respective Tariffs.

The EIM utilizes bids from voluntarily offered Participating Resources to come up with the most economical and reliable dispatch of generation to meet load and interchange demands. One of the primary benefits of the EIM is that it leverages the geographical diversity of resources and loads across the entire EIM footprint, which is much larger and more diverse than any single balancing authority area.

The EIM is comprised of a 15-minute market (FMM) and a 5-minute real time dispatch (RTD). This means the market clears every 15 minutes for the FMM (four intervals each hour) and every 5 minutes for the RTD (12 intervals each hour).

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[15] Western EIM Benefits Report, First Quarter 2019, CAISO, at 15 (Apr. 29, 2019), *available at* https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx. "If not for energy transfers facilitated by the EIM, some VERs located within the ISO would have been curtailed via either economic or exceptional dispatch. The total avoided renewable curtailment volume in MWh for Q1 2019 was calculated to be 8,216 MWh (January) + 6,243 MWh (February) + 37,795 MWh (March) = 52,254 MWh total." *Id.* at 14.

[16] *Id.* at 3.

[17] For more detailed information on the EIM, please see Bonneville's "EIM 101" presentation, dated September 13, 2018, *available at* https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20180913-September-13-2018-EIM-101-Workshop.pdf, or viewed by video at https://www.youtube.com/watch?v=ChYJRXEIADk.

EIM-Related Agreements and Relationships

When a balancing authority area joins the EIM, it becomes an EIM Entity. Prior to becoming an EIM Entity, the balancing authority must sign an Implementation Agreement that commits the balancing authority and the CAISO to work together on implementing the necessary systems and processes so that the CAISO can operate the EIM in the balancing authority area.[18] An Implementation Agreement terminates once EIM transactions in the EIM Entity's balancing authority area become financially binding.

Before beginning financial transactions in the EIM, the balancing authority and the CAISO will sign an EIM Entity agreement, which is an enabling agreement that allows the CAISO to operate the EIM in the balancing authority area. The EIM Entity agreement requires an EIM Entity to abide by the terms and conditions of the CAISO's Tariff applicable to the EIM.

Generation resources in an EIM Entity's balancing authority area can be either a Participating Resource or a Non-participating Resource. A Participating Resource elects to voluntarily participate (or bid) into the EIM. In order to become a Participating Resource, the entity marketing the output of the resource must sign a Participating Resource agreement with the CAISO, which is an enabling agreement that requires the marketer of the Participating Resource to abide by the terms and conditions of the CAISO's Tariff applicable to the EIM. A Non-participating Resource is a resource within the EIM Entity balancing authority area that elects not to participate in the EIM and does not have a direct relationship with the CAISO.

EIM Entities and marketers of Participating Resources must designate a Scheduling Coordinator to submit EIM schedules to the CAISO and receive settlement invoices from the CAISO. The roles and responsibilities of each type of coordinator are memorialized in an EIM Entity Scheduling Coordinator agreement or Participating Resource Scheduling Coordinator agreement.[19] The CAISO does not settle directly with Non-participating Resources or individual load serving entities within an EIM Entity's balancing authority area.

[18] See section IV below for a detailed discussion on the specifics of Bonneville's draft Implementation Agreement, which is attachment C.
[19] For more information on the various agreements the CAISO requires and the process for joining the EIM, please see slides 11-18 of the November 14, 2018, public EIM stakeholder presentation at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20181113-Nov-14-2018-EIM-Stakeholder-Mtg.pdf.

Resource Participation

Resource participation in the EIM is voluntary both in terms of whether to become a Participating Resource and whether to participate in any given hour. Moreover, as described in further detail below, marketers of multiple Participating Resources can choose to aggregate resources when certain parameters are met, or even choose to designate certain portions of aggregated resources as participating and non-participating.[20] Participating Resources submit incremental and/or decremental bid ranges with specified price curves to the CAISO for every hour, and the CAISO will provide dispatch instructions to the Participating Resource's Scheduling Coordinator if the market run determines that the Participating Resource should move within the parameters of the bid range.[21]

Transmission

The EIM utilizes transmission made available to facilitate the dynamic transfers of energy between EIM Entities' balancing authority areas that may result from the market optimization. The CAISO honors physical transmission constraints within each EIM Entity's balancing authority area while running the market. The lack of transmission for EIM transfers may result in a less economical dispatch and higher prices for energy.

Transmission is provided in the EIM consistent with non-discriminatory open access principles. Currently, there is no explicit charge for transmission usage in the EIM. EIM Entities provide or allow transmission for EIM transfers in one of two ways. First, an EIM Entity can directly provide unused transmission for EIM transfers at no charge. Second, an EIM Entity may allow transmission customers to donate their transmission rights and allow that transmission to be used for EIM transfers.[22]

Market Operation & Timelines

For the EIM to operate smoothly, it has a series of hourly timelines that the EIM Entity, Participating Resources, and the CAISO must follow.[23] In general terms, the timeframes dictate when EIM Entities and Participating Resources must submit initial and revised base schedules and bid curves for Participating Resources, which the CAISO will use in its

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[20] See section III.e.1 for more information on how Bonneville is proposing to aggregate federal resources for participation in the EIM.
[21] Section III.e.1 describes how Bonneville plans to participate with federal resources in the EIM. Non-federal resource participation is discussed in section V.e.
[22] See section III.e.2 for more information on Bonneville's proposal regarding transmission donation.
[23] Bonneville conducted an "EIM 101" presentation for stakeholders on September 13, 2018, where the EIM market timelines were discussed in detail. The presentation and video can be accessed at the links provided in footnote 17, above.

market dispatches and settlement statements. The hourly timeframes also dictate when the CAISO must run and publish the results of its resource sufficiency evaluation to ensure that EIM Entities make available sufficient resources, transmission, and flexible capacity in their respective balancing authority areas to be allowed to participate in the EIM and not lean on resources in other balancing authority areas. The timelines also dictate when the CAISO must issue dispatch instructions and orders to the 15-minute and 5-minute real-time dispatch markets.

The CAISO uses the base schedules and bid range provided by EIM Entities and Participating Resources to calculate the most economic dispatch based on available transmission, transmission congestion, and losses. This dispatch results in Locational Marginal Prices (LMPs) and Dispatch Operating Targets (DOTs) for Participating Resources, occurring every 15 and 5 minutes. The CAISO also updates dynamic schedules to facilitate the optimal transfers of energy between EIM Entities.

Base schedules submitted by EIM Entities and Participating Resources become financially binding within the hour, and the CAISO uses them to generate settlements statements. Separate settlement statements are issued to the EIM Entity Scheduling Coordinator and Participating Resource Scheduling Coordinator.

EIM Settlements

The EIM is financially settled through the settlement system administered by the CAISO. Each week, the CAISO issues settlement statements to the Scheduling Coordinators for EIM Entities and Participating Resources containing their respective shares of the costs or payments associated with the EIM. The CAISO's settlement system allocates costs and payments to EIM Entities and Participating Resources in accordance with a series of charge codes that are described in detail in the CAISO's Tariff, Business Practice Manuals, and Configuration Guidelines.

While the CAISO issues settlement statements to the Scheduling Coordinators for EIM Entities and Participating Resources, it does not dictate how EIM Entities sub-allocate the benefits and costs of EIM participation to their customers. Rather, EIM Entities are responsible for developing the appropriate Tariff provisions and business practices describing and implementing the sub-allocation of EIM-related benefits and costs.[24]

[24] See section V.b below for Bonneville's proposed process for developing policies regarding the sub-allocation of EIM-related benefits and costs.

EIM Governance

The EIM is governed by two decisional bodies: the CAISO Board of Governors and the EIM Governing Body.[25] The scope of each body's authority depends on whether the matter is EIM-specific or broadly applicable to all CAISO market participants. The members of the CAISO Board of Governors are appointed by the Governor of California and meet the independence criteria for organized markets promulgated by FERC.[26] The EIM Governing Body consists of five members that act independently of market participants and stakeholders.[27]

In particular, the EIM Governing Body has authority to approve all issues that fall entirely within its "primary" authority, *i.e.*, EIM-specific rules that apply uniquely to EIM balancing authority areas.[28] Such decisions are then added to the consent agenda of the CAISO Board of Governors, meaning the EIM Governing Body's decision is deemed approved unless the CAISO Board of Governors takes an affirmative action to disapprove of the decision. The CAISO Board of Governors cannot modify Tariff provisions that are within the primary authority of the EIM Governing Body unless the EIM Governing Body first approves the Tariff modification.[29] The CAISO Board of Governors considers all other EIM matters—those not within the EIM Governing Body's primary authority—on a non-consent agenda basis. The EIM Governing Body can act in an advisory capacity to the CAISO Board of Governors on all such matters. Finally, any substantive changes to the EIM Charter must first be presented to the EIM Governing Body for advisory input and then approved by the CAISO Board of Governors.[30]

The EIM Charter establishes two additional bodies to inform EIM Governing Body decision-making: the Body of State Regulators (BOSR) and the Regional Issues Forum (RIF). The BOSR is a self-governing advisory body comprised of one utility commissioner from each

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[25] Bonneville presented an overview of the EIM governance structure in a stakeholder meeting, dated October 11, 2018. The presentation can be accessed at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20181011-October-11-2018-EIM-Stakeholder-Mtg.pdf.

[26] *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*: *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 75 FERC ¶ 61,080, at 280 (1996), 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (explaining that a market operator's independence with respect to governance and with respect to financial interests is fundamental to a functional and competitive market).

[27] Charter for Energy Imbalance Market Governance, CAISO, § 1.1 (rev. Mar. 27, 2019) (EIM Charter), *available at* https://www.westerneim.com/Documents/CharterforEnergyImbalanceMarketGovernance.pdf.

[28] *See also* Guidance for Handling Policy Initiatives within the Decisional Authority or Advisory Role of the EIM Governing Body, CAISO (rev. Mar. 27, 2019), *available at* https://www.westerneim.com/Documents/GuidanceforHandlingPolicyInitiatives-EIMGoverningBody.pdf.

[29] EIM Charter § 2.2.

[30] *Id.* at § 8.

state within the EIM footprint. The BOSR operates as a vehicle for states to identify and convey potential concerns related to EIM impacts on state policies and the retail customers of regulated utilities within their jurisdiction. Publicly owned utilities have no direct representation on the currently constituted BOSR because publicly owned utilities generally fall outside the jurisdiction of a state's public utility commission. The RIF is a forum for stakeholders from various sectors to discuss broad issues related to EIM participation and market design.[31] However, the RIF cannot consider EIM issues that are within an ongoing CAISO policy initiative. The EIM Charter allots each stakeholder sector two liaisons to represent its interests on the RIF.[32] Bonneville is an active participant on the RIF and currently holds one of the two Neighboring Balancing Authority sector liaison seats.

As required by the EIM Charter, there is currently a stakeholder process underway to review the EIM governance structure.[33] In response to stakeholder feedback, the EIM Governing Body commenced its evaluation of EIM governance in December 2018 by releasing a governance review straw proposal for public comment.[34] The CAISO plans to establish a stakeholder-comprised governance review committee to develop a governance proposal(s) through an iterative public process. The committee's proposal(s) for changing the governance structure would then be presented to the EIM Governing Body and Board of Governors for review and approval.

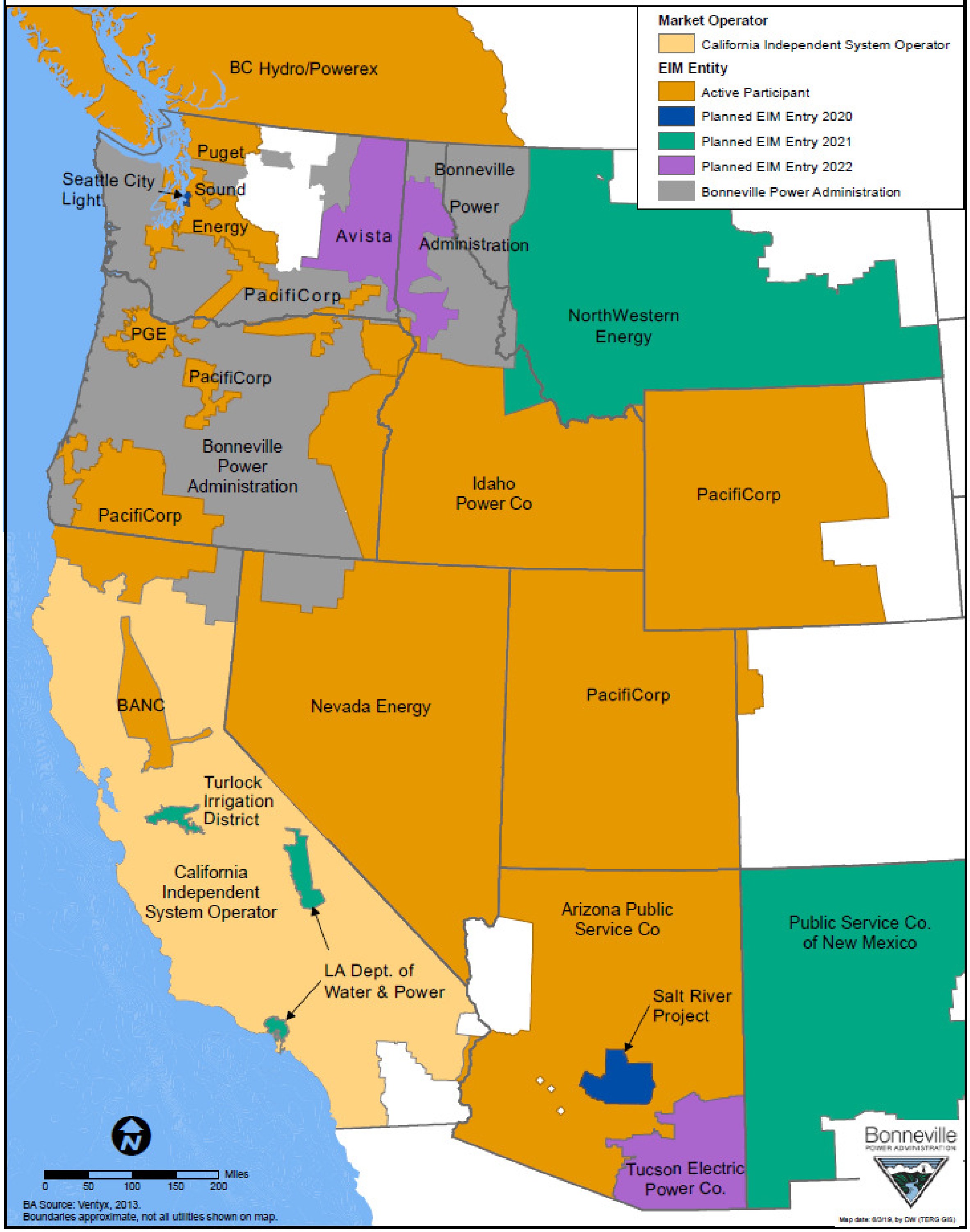
c. Why Bonneville Is Considering Joining the EIM

As described in section I.a, the electric industry in the West is changing rapidly. Although initially developed as a market between the CAISO and PacifiCorp in 2014, the EIM has quickly expanded and now includes participants in two countries and nearly the entire Western Interconnection. Participating entities include, or will include, both private (investor-owned) and public utilities. Many of the EIM Entities now utilizing the EIM to help balance loads and generation in their balancing authority areas are bilateral trading partners with Bonneville.

[31] *Id*. at § 6.
[32] *Id*. at § 6.2.
[33] *Id.* at § 2.2.4.
[34] *See* EIM Governance Review: Issue Paper and Straw Proposal, CAISO (Dec. 14, 2018), *available at* https://www.westerneim.com/Documents/IssuePaperandStrawProposal-EIMGovernanceReview.pdf.

Attachment A

Western Interconnect Balancing Authority Areas: Energy Imbalance Market



In light of this rapid industry change and evolution, Bonneville must be ever diligent in exploring ways to maximize the value of the federal power and transmission systems. This means looking for additional marketing opportunities and improving the operations of the federal power and transmission systems.

Over the last two decades, Bonneville has participated in multiple attempts to form an organized market in the Northwest, but for a number of reasons these attempts have failed and the fundamental market for the region continues to be bilateral trades. The EIM is unlike the region's other attempts to create an organized market because it is simply an extension of an existing real-time market. Other market creation efforts attempted to form a Northwest regional transmission organization with full day-ahead markets or other features formed from the ground up, and while regional parties could agree on high level concepts there were always problems solving the details of new market creation.

The EIM, on the other hand, is limited to a real-time market, and all the detailed features have been vetted through multiple stakeholder processes and approved by FERC. Rather than having to build regional consensus around the development of a new market, Bonneville only needs to determine if the EIM in its existing form will work for Bonneville and its customers.

Bonneville has been involved with the creation of the EIM since its early stages. In 2014, the CAISO and PacifiCorp formed the EIM by extending the CAISO's real-time market to PacifiCorp's balancing authority areas. Bonneville had a role because PacifiCorp's western balancing authority area is intertwined with the federal transmission system, and PacifiCorp needed to use its transmission rights on Bonneville's system to make the EIM work.

Bonneville holds transmission contracts with PacifiCorp to serve several Bonneville preference customers, and service under these contracts was affected by the creation of the EIM. Bonneville worked collaboratively with PacifiCorp and the CAISO to accommodate EIM transfers on the federal transmission system and to preserve the rights of our preference customers within PacifiCorp's balancing authority area.

Subsequently, Bonneville has worked with the other Northwest utilities that have joined the EIM. Our role has been to accommodate their use of the Bonneville transmission system while ensuring that the EIM does not impact reliability or any other uses of the system.

In addition, Bonneville has worked closely with the CAISO to develop the Coordinated Transmission Agreement, which established the parameters for how the CAISO will operate the EIM to ensure the continued reliability of the Bonneville transmission system, and provided for data sharing requirements that improved visibility of the impacts of the EIM on the Bonneville transmission system. Through all these efforts Bonneville has gained a detailed understanding of how the EIM operates, and Bonneville has taken a specific interest in the EIM rules, governance, and stakeholder processes.

Bonneville's Strategic Plan

Bonneville's Strategic Plan outlines the actions the agency will take "to leverage and enable industry change through modernized assets and system operations, and to deliver on our public responsibilities through a commercially successful business."[35] It outlines four strategic goals for the 2018-2023 timeframe:

1. Strengthen financial health.
2. Modernize assets and system operations.
3. Provide competitive power products and services.
4. Meet transmission customer needs efficiently and responsively.[36]

Bonneville's participation in the EIM would be consistent with these strategic goals, and it would leverage industry change that is already happening. Many other entities have joined the EIM, VERs generation output is increasing, and with the help of the EIM system operators are squeezing greater efficiencies from existing transmission and generation assets. Signing the Implementation Agreement is a first step that allows Bonneville to work with the CAISO to develop Bonneville's potential participation in the EIM into a strategic tool that helps ensure Bonneville can more efficiently and effectively meet its obligations while continuing to navigate this period of heightened change in the industry.

Joining the EIM is consistent with Bonneville's goals of increasing its market opportunities and improving the operation of the federal power and transmission systems. As discussed further below, Bonneville's cost-benefit analysis indicates that Bonneville's participation with federal generation resources in the EIM could result in approximately $29-34 million of additional revenue annually for Bonneville. While Bonneville is proposing to join the EIM and pursue these revenue opportunities through bidding federal resources into the EIM, Bonneville will also continue to pursue other opportunities with bilateral transactions and other markets.

Participation in the EIM would also provide Bonneville with valuable new tools to address transmission congestion. Given the diversity of loads and resources now located in the EIM

[35] Bonneville 2018-2023 Strategic Plan at 3 (Jan. 2018), *available at* https://www.bpa.gov/StrategicPlan/StrategicPlan/2018-Strategic-Plan.pdf.
[36] *Id.* at 9.

footprint, Bonneville could leverage the EIM to help address constrained paths in its balancing authority area. Bonneville is well positioned to facilitate solutions to manage the growing congestion in California because of its role as operator of the principal transmission lines connecting the Pacific Northwest with Northern and Southern California, the California-Oregon Intertie and the Pacific DC Intertie respectively. In addition, Bonneville's merchant has a portfolio of firm rights on these paths that it could use for beneficial commercial solutions.

Another benefit to Bonneville becoming an EIM Entity is that it would gain access to additional data and information that would enhance system operations through greater visibility and situational awareness. In 2018, Bonneville initiated a comprehensive "Grid Modernization" project in an effort to update and modernize its systems and processes. This effort is necessary for Bonneville to remain competitive and operate as efficiently as possible. As an EIM Entity, Bonneville would gain access to certain operational tools that would add greater discipline and help operate its balancing authority area more efficiently.

Consistent with its Strategic Plan, Bonneville is also considering other opportunities to market flexible carbon-free federal power. One such opportunity is the CAISO's effort to develop a day-ahead product that incents the commitment of additional flexible capability from resources that can be deployed in real-time. Such a product would provide an opportunity for Northwest hydro and other dispatchable resources that can quickly ramp up or down to make up for unscheduled changes in load and generation. These valuable capabilities will support the reliability of the Western transmission grid as we work to integrate large amounts of additional renewable energy generation. Bonneville has taken an active role in the CAISO's ongoing effort to develop a day-ahead flexible ramping product. Bonneville expects that the CAISO will complete its stakeholder process and implement this product before Bonneville goes live in the EIM.

II. Decision-making Framework for EIM Participation

Overview

Signing an Implementation Agreement is a significant milestone and involves considerable commitment of time and resources. Bonneville has divided joining the EIM into a multi-year series of incremental decisions that culminate in a possible go-live in March of 2022. This series of decisions will determine how Bonneville will participate and how that participation will affect other parties doing business with Bonneville. This step-wise decision making framework limits upfront costs and risks and outlines a clear plan for moving through the various stages required to decide on implementing, joining, and participating in EIM.

Bonneville's series of incremental decisions are divided into five phases. Through these Bonneville will decide whether and how to join the EIM, as well as navigating the required implementation steps for participation in the EIM. The five phases of Bonneville's decision process are:

1. Phase I – Exploration from July 2018 through June 2019
2. Phase II – Implementation Agreement, EIM principles, and some policy decisions from June 2019 through September 2019
3. Phase III – Additional policy decisions from October 2019 through August 2020
4. Phase IV – Rate and Tariff Proceeding from October 2020 through July 2021
5. Phase V – Close-Out Letter from October 2021 through December 2021

Each phase is described below.

Phase I – Exploration (July 2018 to June 2019)

Phase I was EIM exploration for Bonneville and its stakeholders, the time immediately preceding this Proposal during which Bonneville and stakeholders were learning about the mechanics of the EIM and exploring details and nuances related to joining and participating in the EIM. During the exploration phase, from July 2018 through June 2019, Bonneville held monthly public meetings on particular topics related to the EIM. Bonneville sought informal comment from stakeholders, and those comments were addressed verbally at subsequent public meetings or one-on-one with the commenter.

The topics discussed in the meetings during the exploration phase are the following:

1. Treatment of Transmission
2. Generation Participation Model (FCRPS)
3. EIM Governance
4. Cost-Benefit Analysis
5. Balancing Authority Area Resource Sufficiency
6. EIM Settlements
7. Use of Reliability Tools such as Operational Controls for Balancing Reserves (OCBR) and Oversupply Management Protocol (OMP)
8. Load Zone
9. Market Power and Default Energy Bid (DEB)
10. Carbon Obligation in the EIM
11. Relationship of the EIM to other emerging markets

The materials presented at those meetings and comments received are posted at https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx. In addition to the monthly public meetings, Bonneville staff met with stakeholders who requested meetings to discuss specific issues of interest to them during the exploration phase.

Phase II –Implementation Agreement and high level issue analysis, including deciding on overarching principles for joining the EIM, and decisions on several policy issues (June 2019 to October 2019)

Phase II has been initiated with the publishing of this Proposal. This Proposal and the associated policy development, stakeholder comments, and Bonneville responses are the key components of Phase II. The Proposal includes a proposal to sign the Implementation Agreement, a discussion of Bonneville's legal authority and business reasons for considering joining the EIM, proposed principles that Bonneville will follow throughout the remaining phases of Bonneville's EIM decision process, and proposed policy decisions on certain issues that have been covered in Bonneville's stakeholder meetings during Phase I of the process. Stakeholders may comment on the content of this Proposal, and then Bonneville will publish a Record of Decision (ROD) addressing comments received. The ROD will contain Bonneville's decision on whether to sign the EIM Implementation Agreement with the intent to join the EIM in 2022 and will respond to comments on the other policy and implementation decisions covered in this Proposal.

In Phase II, Bonneville is moving on to development of systems and technical knowledge of the EIM to position itself to participate in the EIM. Signing the Implementation Agreement initiates a particular set of technical work by the CAISO and Bonneville to prepare for Bonneville's potential participation in the EIM, and it commits Bonneville to pay the CAISO six equal payments of $311,650, due upon the completion of six milestones, for a total payment of $1,870,000. In addition, Bonneville will initiate a series of investments in internal systems and processes that are estimated to cost $30-35M (Start-up costs).[37]

The decisions that are proposed to be made or established in the September 2019 ROD are:

1. Whether to sign the EIM Implementation Agreement,
2. Bonneville's legal authority to join the EIM,
3. Bonneville's business case for joining the EIM,
4. What Bonneville's EIM principles will be, and

[37] Section III.d.2.i discusses these start-up costs.

5. Decisions on the following policy issues:
    a. Federal Generation Participation Model
    b. Transmission Usage—Interchange
    c. Use of Reliability Tools such as OCBR and OMP
    d. Carbon Obligations and related considerations
    e. Market Power (Local Market Power Mitigation (LMPM) and DEB)
    f. Load Zone
    g. Resource Sufficiency—Balancing Authority Area

The decisions being made in the September 2019 ROD will be final decisions, meaning stakeholders' opportunity to raise issues and concerns regarding these proposals is during the current comment period. After Bonneville makes decisions on these issues in the September 2019 ROD, those decisions will not be revisited during subsequent phases of this decision process unless there is a significant change in the underlying facts or in the way the EIM operates. Although the decisions being made in the September 2019 ROD will be final decisions, they will not be ripe for judicial review unless and until Bonneville makes a decision to join the EIM. Bonneville seeks stakeholder comment on all decisions being proposed in this Proposal. Comments are due on July 22, 2019. Bonneville will issue a ROD in September 2019 addressing comments received and making decisions on the items listed above.

Phase III – Additional Policy Decisions (October 2019 to August 2020)

If the outcome of Phase II is that Bonneville decides to sign the Implementation Agreement, Phase III will commence immediately after Bonneville publishes the ROD in September 2019 and signs the Implementation Agreement. During Phase III Bonneville will continue holding EIM stakeholder meetings to discuss the remaining important policy issues that are not being covered in this Proposal and the ROD.

The policy issues that will be addressed in Phase III are the following:

1. Transmission Usage—Network
2. Allocation of EIM Charge Codes
3. Resource Sufficiency—Sub-Balancing Authority Area level
4. Transmission Losses
5. Non-federal Resource Participation Requirements
6. Settlements/Billing (Mechanics)
7. Data Submission Requirements
8. Metering Requirements

If Bonneville learns of additional policy issues that need resolution, they will be added to this list.[38]

During Phase III, EIM stakeholder meetings will continue and will flow into pre-rate and pre-Tariff proceeding workshops as appropriate. Some of the policy issues may be resolvable outside of the rate and Tariff proceedings. For those issues, Bonneville will present written proposals covering the issues, take formal written comments on these proposals, and will issue decision documents addressing the comments received and setting out decisions on these policy issues. For issues that will need to be decided in the rate and Tariff proceedings, those issues will continue to be discussed in pre-rate and pre-Tariff proceeding workshops in preparation for the TC-22 and BP-22 proceedings.

Phase IV – Tariff Terms and Conditions Case and Rate Case (October 2020 to July 2021)

During Phase IV, the policy decisions made in Phases II and III will be implemented through the TC-22 Tariff Terms and Conditions proceeding and the BP-22 rate case proceeding. The TC-22 proceeding will establish EIM-related terms and conditions that will become part of Bonneville's Tariff and will apply to Bonneville's transmission customers. The BP-22 rate proceeding will establish the EIM-related rates and cost allocations that will apply to Bonneville customers. The EIM terms and conditions and the applicable rate changes associated with EIM participation will not become effective until Bonneville begins participation in the market. Thus, the applicability of the EIM terms and conditions and rates will depend on Bonneville's final decision regarding joining the EIM, which will take place after the cases are completed and during the BP-22 rate period.

The BP-22 proceeding is a well-established process that follows section 7(i) of the Northwest Power Act, 16 U.S.C. § 839e(i), and associated rules, Final Rules of Procedure, 83 Fed. Reg. 39,993 (Aug. 13, 2018). The EIM-related rates that result from the BP-22 proceeding will be final decisions, reviewable pursuant to section 9(e)(1)(G) of the Northwest Power Act, 16 U.S.C. § 839f(e)(1)(G). The TC-22 proceeding is conducted in accordance with section 9 of Bonneville's Tariff, which provides the Administrator with the ability to change Tariff terms and conditions after conducting a proceeding in accordance with Section 212(i)(2)(A) of the Federal Power Act (requiring the proceeding to follow most of the processes set forth in section 7(i) of the Northwest Power Act) and issuing a final decision which considers factors set forth in Tariff section 9. The EIM-related terms

[38] These issues are described and discussed briefly in section V.

and conditions adopted by the Administrator in the TC-22 proceeding will be final decisions.

Phase V – Close-Out Letter (October 2021 through December 2021)

After the conclusion of the TC-22 and BP-22 proceedings, Bonneville will make a final decision whether to join the EIM. If Bonneville's choice is to join the EIM, Bonneville will write a letter stating that proposed decision and setting out how that decision is consistent with Bonneville's principles for joining the EIM that are being established in Phase II. Stakeholders will have an opportunity to comment on this proposed decision, and then Bonneville will publish a final Close-Out Letter addressing the comments received and setting out its decision on joining the EIM. If Bonneville makes the decision to join the EIM, that will be a final action ripe for judicial review under section 9(e) of the Northwest Power Act, 16 U.S.C. § 839f(e).

If Bonneville makes the decision to join the EIM, Bonneville plans to begin financial binding transactions in the EIM (Go Live) in March 2022. Bonneville will sign an EIM Entity Agreement and the various other CAISO agreements necessary for joining and participating in the EIM before the Go Live date.

The above proposed process is intended to provide a transparent roadmap for Bonneville and its stakeholders that will provide structure and opportunity for input to the multiple decisions that are required for Bonneville to join the EIM. Please provide comments on this proposed process.

III. Proposed Determinations and Policies for Joining the EIM

a. Bonneville's EIM Participation Principles

Proposal: Bonneville proposes to adopt the four principles discussed in more detail below as the foundational principles that Bonneville will continue to use in its evaluation of potentially joining the EIM. Bonneville seeks stakeholder input and comment on each of these principles, and on whether additional principles should be considered.

Given Bonneville's status as a federal power marketing administration and mandate to market the output of federal resources while reliably serving loads in the Pacific Northwest, Bonneville believes it is important to first identify and apply a set of foundational principles to its potential participation in the EIM. In that regard, Bonneville has identified and is proposing the four principles discussed below. Bonneville first identified and solicited feedback on these principles at its October 11, 2018, EIM stakeholder meeting. Bonneville has identified, discussed, and reviewed the principles in every monthly subsequent stakeholder meeting. Bonneville has modified the principles in response to stakeholder comment since first proposing them.

As discussed in section II, Bonneville will continue to apply these principles throughout the EIM process. The principles will form the basis for Bonneville's decision in the final Close-Out Letter to either join or not join the EIM.

It is important to note that these principles are high-level and foundational to Bonneville's participation in the EIM. As Bonneville progresses through the process of potentially joining the EIM, certain issues will require the development and application of more specific principles. For example, the potential development of additional standards regarding resource sufficiency within Bonneville's balancing authority area or the allocation of the benefits/costs of EIM participation will likely require more specific principles. Such principles will be developed in the appropriate stakeholder process during Phase III.

1. Participation Is Consistent with Statutory, Regulatory, and Contractual Obligations

Bonneville's potential participation must be consistent with its statutory, regulatory, and contractual obligations. Section III.b discusses whether Bonneville's participation in the EIM as it is currently constructed would be consistent with these obligations. Bonneville's analysis preliminarily concludes, subject to stakeholder comment and input, that Bonneville's participation would be consistent. In the event Bonneville determines in the future that EIM participation would no longer be consistent with these obligations, it would cease participating in the market and address the inconsistency. Conceptually, this could arise if the CAISO implemented a Tariff provision or business practice, or FERC ordered a change to the current EIM, that was inconsistent with the statutory, regulatory, or contractual obligations applicable to Bonneville.

2. Maintain Reliable Delivery of Power and Transmission to Our Customers

Even if Bonneville joins the EIM, Bonneville still retains the responsibility for the operation of the federal power and transmission systems. Joining the EIM does not obviate Bonneville's responsibility regarding system reliability. If Bonneville were to determine in the future that EIM participation impaired its ability to maintain the reliability of the federal power or transmission systems, it would stop participating in the EIM and address the reliability issue. In fact, participation in the EIM should help system reliability in terms of managing transmission constraints on Bonneville's transmission system.[39]

3. Resource Participation in the EIM Is and Always Will Be Voluntary

In regard to resource participation, the EIM is a voluntary market. Owners/operators of resources inside the Bonneville balancing authority area can choose whether to participate or not. As described in section I.b, those that choose to participate, including Bonneville on behalf of the federal generating resources, must execute a Participating Resource agreement with the CAISO. Moreover, even owners/operators that sign a Participating Resource agreement with the CAISO are not required to submit bids for any particular market interval. Stated another way, the EIM does not impose "must-run" requirements on any resources within an EIM balancing authority area. Bonneville recognizes that in some cases, if it chooses not to bid federal generation into the EIM, there may be a reduction in dispatch benefits. Furthermore, Bonneville, in its role as an EIM entity, may choose to separate from or exit the EIM if conditions arise that are inconsistent with these principles.

4. Bonneville's Decision to Participate in the EIM Will Be Based on a Sound Business Rationale

Bonneville's decision whether to join the EIM will be based on a reasoned business decision. The decision will include a business case which considers both quantitative and qualitative benefits to power and transmission as well as the strategic value of joining the EIM. The business case is discussed in section III.d.

Conclusion

Bonneville is proposing to make these four principles final in terms of the high-level, foundational principles that drive Bonneville's determination whether to join the EIM. The final determination in Bonneville's Close-Out Letter will utilize these principles in making the decision. Bonneville requests stakeholder input on these principles and whether other, additional principles should be considered.

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[39] Bonneville's system operations tools are discussed in Section III.e.3.

b. Bonneville's Legal Authority to Join the EIM

Introduction

Joining the EIM will require operational changes for both Bonneville power and transmission functions, and it will expose Bonneville to new governance and regulatory structures. Bonneville's legal evaluation of the proposed changes at this early stage of the decision process is critical to ensure that there are no legal barriers to Bonneville's potential participation. It is also important to identify the important legal issues early in the process to inform the stakeholder process.

Bonneville's preliminary determination is that it has the legal authority to join the EIM and that a decision to join the EIM is consistent with its statutory obligations and legal requirements. Bonneville assessed the following issues to determine whether Bonneville's statutory and contractual obligations are consistent with a decision to join the EIM.

1. General authority to operate in a business-like manner and to join the EIM
2. Obligations with respect to preference to power and surplus power requirements
3. Obligation to make sales from the Federal System and bidding power into the EIM from specific projects or groups of projects
4. Statutory authority to provide transmission service
5. Consistency with contractual commitments: Power Contracts and Transmission Contracts
6. Federal Energy Regulatory Commission jurisdiction with respect to Bonneville as an EIM entity
7. Market oversight under the CAISO Tariff
8. Governance

The following legal assessment is based on Bonneville's current understanding of the EIM. If there are significant structural or organizational changes to the EIM after this decision, Bonneville will evaluate those changes as Bonneville moves through the implementation stage toward participation to ensure continued consistency with Bonneville's legal obligations.

1. Joining the EIM Is an Exercise of Bonneville's Authority to Operate in a Business-Like Manner

Position: The Administrator's decision to join the EIM furthers Bonneville's business interests consistent with its power marketing directives and legal requirements.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by the federal projects. In the Bonneville Project Act of 1937, the Secretary of the Army was directed to provide the Administrator with such space and equipment at the Bonneville Dam as may be necessary to transmit the energy produced at the dam "to the markets which the administrator desires to serve."[40] Congress also granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[41] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[42] Bonneville must set rates for the sale of power from these projects pursuant to several principles, including setting rates "consistent with sound business principles."[43] 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 business-like manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing BPA's operations] reflects a congressional recognition of the significant role played by BPA 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 BPA from the Department 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.[44]

The ability of Bonneville to adapt to the ever-changing landscape of the energy market like a business is particularly important because the Administrator must implement many, and often competing, statutory directives. Similarly, the Ninth Circuit Court of Appeals has

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[40] Bonneville Project Act, 16 U.S.C. § 832a(a).
[41] *Id.* § 832a(f). *See* S. R. No. 469, 79th Cong., 1st Sess. 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).
[42] Transmission System Act of 1974, § 8, 16 U.S.C. § 838f.
[43] Flood Control Act of 1944, 16 U.S.C. § 825s.
[44] S. R. No. 164, 95th Cong., 1st Sess. 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.

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."[45] Further, Bonneville must explain how its decision furthers the agency's business interests or its public mission.[46]

The EIM presents a unique opportunity for Bonneville to further its business interest by entering a new market that is expected to provide Bonneville, through its transmission and power functions, significant economic and operational benefits. Much of the western half of the United States is undergoing unprecedented changes in its energy industry and markets. As described earlier, almost all of Bonneville's interconnected balancing authorities in the West have or are in the process of joining the EIM. If Bonneville takes no action, it could stand alone as the sole western balancing authority area to choose not to take the opportunity to benefit from participation in the EIM. Bonneville's consideration of whether to join or participate in an EIM in furtherance of its power and transmission marketing efforts is an important consideration in how Bonneville will meet its mission objectives in the future.

As explained below in section III.d, Bonneville's decision to join the EIM would be founded on significant projected quantitative and qualitative benefits to Bonneville and its customers. In addition, Bonneville believes that joining the EIM will support its ability to meet its statutory obligations. Bonneville's proposed model for participating in the EIM is intended to further Bonneville's business interests consistent with its public mission and to ensure its public and contractual responsibilities and obligations continue to be met first.

2. Joining the EIM Is Consistent with Preference and Surplus Requirements

<u>Position</u>: Bonneville's proposed participation in the EIM is consistent with the preference and surplus requirements of federal law.

<u>Preference</u>

Bonneville's authority to sell federal power is grounded in several statutes: the Bonneville Project Act of 1937,[47] the Pacific Northwest Consumer Power Preference Act of 1964,[48] the

[45] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 2003).
[46] *Pac. Nw. Generating Co-op v. Bonneville Power Admin.*, 550 F.3d 846, 861 (9th Cir. 2009).
[47] *See* 16 U.S.C. §§ 832 *et seq.*
[48] *See* 16 U.S.C. §§ 837 *et seq.*

Federal Columbia River Transmission System Act of 1974,[49] and the Pacific Northwest Electric Power Planning and Conservation Act of 1980.[50] Collectively, these statutes form the basis for Bonneville's power marketing authority, but also prescribe the Administrator's obligation to provide preference and priority to public body and cooperative customers over non-preference entities (investor-owned utilities and direct service industrial customers) when there are competing requests for power.[51] After these regional power customers' needs have been met, Bonneville, on a discretionary basis, can sell power as available to other entities both in and out of the Pacific Northwest region.[52] Meeting public and regional preference directives is a fundamental statutory obligation for Bonneville.

Bonneville's proposal to join the EIM is consistent with the provisions of law relating to public and regional preference. The EIM is a voluntary market and Bonneville is not required to bid in federal generation. If there are competing applications from eligible customers for Bonneville's power, Bonneville will follow the statutorily prescribed order of sales, giving applicable preference to public bodies and cooperatives, then regional customers, and finally to out-of-region purchasers. The EIM does not change Bonneville's statutory marketing paradigm.

Surplus

Bonneville has historically sold federal power on a long term basis to serve its regional power customers' retail load requirements on a firm and continuous basis.[53] This type of power is known as firm power. Pursuant to section 5(f) of the Northwest Power Act, federal power remaining after Bonneville has met all of its section 5(b), (c), and (d) power

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[49] *See* 16 U.S.C. §§ 838 *et seq.*

[50] *See* 16 U.S.C. §§ 839 *et seq*.

[51] *See, e.g.,* 16 U.S.C. § 832c(a):

> In 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 consumers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives.

See also 16 U.S.C. § 839c(a) ("All power sales under this Act shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."). *See also Aluminum Co. of Am. v. Cent. Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 393 (1984) ("But the 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.").

[52] *See* 16 U.S.C. § 837a; 16 U.S.C. 839c(f); *Aluminum Co. of Am. v. Bonneville Power Admin.*, 903 F.2d 585, 588 (9th Cir. 1990).

[53] *See* Committee report on energy and natural resources, H. R. No. 96-272, 96th Cong. 1st Sess. at 26 (July 30, 1979).

obligations, may be sold as "surplus" power.[54] As with other sales of power from the federal system, Bonneville is required to give preference and priority to public body and cooperative (preference) customers when it offers to sell surplus power.[55] If no preference customers request a purchase of Bonneville's surplus power, Bonneville may sell that power to a regional non-preference customer.[56] If no regional customer purchases the surplus power, Bonneville may then sell such power to out-of-region customers on a preference basis, after meeting certain conditions.[57]

For the reasons set forth in this letter, Bonneville believes the EIM is likely to bolster its ability to fulfill its obligations to meet its regional customers' firm power requirements consistent with its statutes and its customers' contracts. As noted above, the EIM is a voluntary market, meaning Bonneville will determine, each hour, whether and to what extent it will bid any remaining federal capability (after all existing contractual and statutory obligations have been met) into the EIM for economic dispatch. If federal generation is dispatched in response to the EIM, the resulting energy could be used to serve either in region or out of region imbalance. As such, to satisfy the notice requirements of making surplus power sales out of region, Bonneville will update its regional notice of available surplus to include provisions regarding Bonneville's potential sales in the EIM.

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[54] 16 U.S.C. § 839c(f).

[55] Preference applies to the sale of surplus. Section 5(a) of the Northwest Power Act, 16 U.S.C. § 839c(a), states:

> *All power sales* under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 (16 U.S.C. 832 and following) and, in particular, sections 4 and 5 thereof [16 U.S.C. 832c and 832d].

(Emphasis added.)

[56] The conditions include:

> (1) Bonneville must notify Northwest customers of its intent to sell surplus energy out of region (and allow review of draft agreements if requested);
> (2) the sales contract must contain a 60 day notice of termination and recall for energy sales if needed to serve regional energy need; and
> (3) the contract must contain a 60 month notice of termination and recall for capacity sales.

See 16 U.S.C. §§ 837a, 837b(a), (c).

[57] Section 9(c) of the Northwest Power Act, 16 U.S.C § 839f(c), states:

> In applying such sections for the purposes of this subsection, the term "surplus energy" shall mean electric energy for which there is no market in the Pacific Northwest at any rate established for the disposition of such energy, and the term "surplus peaking capacity" shall mean electric peaking capacity for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.

See also § 1(c)-(d) of the Preference Act, 16 U.S.C. § 837(c)-(d):

> "Surplus energy" means electric energy generated at federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate.
>
> "Surplus peaking capacity" means electric peaking capacity at federal hydroelectric plants in the Pacific Northwest for which there is no demand in the Pacific Northwest at any established rate.

3. Bonneville's Decision to Bid Generation into the EIM Is Consistent with Its Obligation to Make Sales from the Federal System

<u>Position</u>: *Bidding in capacity from specific federal hydroelectric dams or groups of federal hydroelectric dams is consistent with Bonneville's statutes.*

<u>*Background and Context*</u>

Bonneville meets its customers' power needs from the FCRPS by selling federal power as a "system sale." Under a "system sale," Bonneville meets its power obligations by using all the electric power produced in aggregate by the FCRPS and acquired non-federal resources. Bonneville's system sales are different than sales from other federal power marketing administrations, which market statutorily-authorized allocations of federal power on a project-by-project basis.

Bonneville's system sale model of marketing power developed as the FCRPS expanded. As each new project in the Columbia River Basin was completed, Bonneville was directed by statute or executive order to market the output of that project. In the Bonneville Project Act of 1937, Bonneville was established to market the power generated from the Corps of Engineers' newly completed Bonneville Dam.[58] Then, in 1940, Bonneville was directed to also market power from the Bureau of Reclamation's Grand Coulee Dam by Executive Order No. 8526.[59] Bonneville was directed to market power from the Corps' lower Columbia projects in the Flood Control Act of 1944,[60] and from the Lower Snake river projects in the Rivers and Harbors Act of 1945.[61] In 1951, Bonneville was directed by Secretarial Order to market power from all Corps projects "now and hereafter constructed in the drainage basin of the Columbia River and its tributaries . . . in the States of Washington and Oregon."[62] Bonneville was similarly directed by Secretarial Order to market power from all Bureau projects in the Pacific Northwest.[63] Regarding rates based on system sales, the Secretary directed Bonneville to "extend the benefits of uniform rate

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[58] Bonneville Project Act, § 2(a), 16 U.S.C. § 832a(a).
[59] Coordinating the Electrical Facilities of Grand Coulee Dam Project and Bonneville Project, 5 Fed. Reg. 3,390 (Aug. 26, 1940).
[60] Flood Control Act of 1944, ch. 665, § 5, 16 U.S.C. § 825s.
[61] River and Harbor Act of 1945, Pub. L. No. 79-14, § 2, 59 Stat. 10, 22 (1945).
[62] Sec. of Interior Order No. 2663, 17 Fed. Reg. 5,197 (1951).
[63] *See* Sec. of Interior Order No. 1994, 9 Fed. Reg. 11,966 (1944) (Hungry Horse); Sec. of Interior Order No. 2115, Amendment 1, 18 Fed. Reg. 2,831 (1953) (Chandler); and Sec. of Interior Order No. 2753, Amendment 1, 22 Fed. Reg. 1,090 (1957) (Roza); Sec. of Interior Order No. 2860, 27 Fed. Reg. 591 (1962) ("all projects now or hereafter constructed in the drainage basin of the Columbia River . . . in Washington and Oregon").

schedules and integrated power services to all parts of his marketing area" in a 1966 order on marketing from Snake River Basin projects.[64] Finally, in the Transmission System Act of 1974, Bonneville was designated as the "marketing agent" for all electric power generated by federal generating plants in the Pacific Northwest, excepting only the electric power required for the operation of each federal project and power from the Green Springs project of the Bureau.[65]

Bonneville's system sales approach is not only historical artifact; Bonneville adopted the system sales approach to comply with various statutory and executive directives. These directives appeared in the early marketing authorizations and refinement in the Northwest Power Act.[66] These directives fall into three general categories:

- Directives to integrate and operate the federal projects as a single system to efficiently and economically market energy;[67]

- Directives to meet the firm power load obligations of Bonneville's customers using "Federal base system resources" (note that resources is plural not singular);[68]

- Directives to recover the "total system costs" of the FCRPS.[69]

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[64] Sec. of Interior Order No. 2860, amended by 27 Fed. Reg. 591 (1962), 28 Fed. Reg. 5, 273 (1963), 31 Fed. Reg. 13,560 (1966) (emphasis added).
[65] Transmission System Act, § 8, 16 U.S.C. § 838f.
[66] Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839 *et seq.*
[67] *See, e.g.,* Secretary of the Department of Interior, Harold Ickes, Senate Committee on Commerce hearings on H.R. 3961 (May 1944):

> Physical integration of the power facilities at these new projects with the existing facilities of the Bonneville Power Administration will be needed for most efficient and economical marketing of energy. At present the Administration maintains a network of high-voltage transmission lines in Oregon and Washington over which the power generated at Bonneville and Grand Coulee Dams is sold, and with which the proposed new projects should be interconnected in order to make the best use of all available power.

[68] The Northwest Power Act, § 3(10), defines "Federal base system resources" as "(A) the Federal Columbia river Power System hydroelectric projects; (B) resources acquired by the Administrator under long-term contracts in force on December 5, 1980; and (C) resources acquired by the Administrator in an amount necessary to replace reductions in capability of the resources referred to in subparagraphs (A) and (B) of this paragraph." 16 U.S.C. § 839a(10). The Regional Preference Act, § 2, provides that "the sale, delivery, and exchange of electric energy generated at, and peaking capacity of, federal hydroelectric plants in the Pacific Northwest for use outside the Pacific Northwest shall be limited to surplus energy and surplus peaking capacity." 16 U.S.C. § 837a. This language refers to federal hydroelectric plants. Because it is in the plural form it is language that encompasses the whole, or interconnected, system of federal hydro projects.
[69] The Northwest Power Act directs the Administrator to establish rates "based upon the Administrator's total system costs" and for requirements customers to "recover the costs of that portion of the Federal base system resources needed to supply such loads. . . ." 16 U.S.C. §§ 839e(a)(2)(B), 839e(b)(1). These rate directives

The EIM is a security constrained economic dispatch that matches loads with the least expensive generation bid into the market taking into account congestion and transmission losses. As such, a general premise of the EIM is that generation bid into the market is not from an aggregated system sale but sourced from specific locations on the integrated grid. This can be either individual generation projects or groupings of projects that are geographically located close to one another so as not to have significantly different impacts on the grid.

Participation in the EIM with federal generation will require specific information on the source of the federal generation being used to respond to EIM dispatches. The legal question is whether Bonneville can provide the specific system information required by the EIM and still comply with the statutory and executive directives that have historically resulted in Bonneville selling power from the aggregated federal system.

Bidding into the EIM Federal Generation at Specific Projects or Group of Projects Is Consistent with Bonneville's Statutory Directives

Bonneville believes that participating in the EIM with specific projects or groups of projects is consistent with the statutory and executive directives that have led Bonneville to historically sell power from the federal system.

First, bidding federal capacity into the EIM, even on an individual project level, will not pose a risk to the integration, coordination, or efficient operation of the federal projects as a single system. Like all participants, Bonneville (in coordination with the Corps and Reclamation) will determine what capacity to bid into the EIM. In this way, federal control will remain over (1) coordinating and controlling the FCRPS projects to meet all federal obligations; (2) determining which projects and generating units will operate and how much flexibility is available at each project; and (3) the amount of transmission that Bonneville Power Services makes available for EIM transactions.[70]

Second, participation in the EIM with specific federal projects will not pose a risk to Bonneville's ability to meet its firm power sales obligations. These obligations will continue to be met from the collective system resources of the FCRPS. The EIM preserves this functionality by allowing Bonneville to include these aggregated obligations as part of

align with the system sale paradigm in that they direct Bonneville to set rates to recover the costs of the entire federal system, which presumes that Bonneville is using the entire system to serve its customers' loads.

[70] See section III.e.1.

the "base schedule"[71] that Bonneville submits to the EIM. As such, Bonneville will retain its current discretion to meet these obligations from the federal projects as a single system.

Third, bidding in capacity from specific federal projects will not impair Bonneville's ability to recover its "total system costs." Bonneville will continue to sell firm requirements power to its regional customers under long-term contracts from system resources at rates set by Bonneville's statutory directives. To the extent Bonneville makes surplus power sales into the EIM, Bonneville will be compensated by the EIM at rates consistent with the bid ranges submitted with Bonneville's dispatches. The cost and benefits of those surplus power sales will, in turn, be included in Bonneville's rates. Thus, Bonneville's ability to recover total system costs from its customers will remain.

4. Joining the EIM Is Consistent with Bonneville's Statutory Authority to Provide Transmission Service

<u>Position</u>: *Bonneville's proposed participation in the EIM is consistent with Bonneville's statutory authority to provide transmission service.*

To join the EIM, Bonneville would have to make certain limited changes to the terms and conditions under which Bonneville provides transmission service to its customers. The changes needed to participate would be EIM-specific and would not fundamentally alter Bonneville's existing paradigm for providing transmission service. For example, as described in section I.b, non-federal resources within an EIM Entity's balancing authority area can be bid into the market as Participating Resources. The EIM also requires that EIM participants submit base schedules on an hourly basis, which is based on the exchange of certain data between entities within the balancing authority area. The specific criteria to facilitate these and other EIM-specific protocols are governed by the EIM Entity's Tariff. Bonneville would consider such EIM-specific changes to the terms and conditions of its Tariff to coincide with its participation in the EIM.

Within Bonneville's broad statutory parameters, the Administrator has the authority to establish terms and conditions for transmission service, including terms and conditions that would reflect EIM membership. This authority arises under section 2(b) of the Bonneville Project Act; section 6 of the Pacific Northwest Consumer Power Preference Act of 1964; and sections 4 and 6 of the Federal Columbia River Transmission System Act.[72] In brief, these statutes authorize the Administrator to operate and build the federal

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[71] *See* section I.b.
[72] 16 U.S.C. § 832a(b); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

transmission system as the Administrator determines is appropriate and necessary for a number of reasons, including the construction of facilities to integrate and transmit federal and non-federal power, provide service to Bonneville's customers, provide interregional transmission facilities, and maintain the stability and reliability of the federal system.[73]

Bonneville's statutes also provide the Administrator with broad authority to establish the terms and conditions of transmission service.[74] Specifically, Section 2(f) of the Bonneville Project Act provides as follows:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof, and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.[75]

This grant of contracting authority to the Administrator is based on the premise that Bonneville operates as a business, and provides Bonneville the needed discretion to function in a business-oriented manner.[76]

If Bonneville decides to join the EIM, it will revise its Tariff in accordance with the process established in the 2020 Terms and Conditions Proceeding. This process, which is set out in section 9 of Bonneville's Tariff, requires Bonneville to conduct a proceeding in accordance with Section 212(i)(2)(A) of the Federal Power Act, and make a decision based on several factors enumerated in section 9(a)(1) of the Tariff.

Bonneville must also revise its transmission and ancillary and control area services rates to join the EIM. Bonneville sets rates in accordance with section 7 of the Northwest Power Act. Section 7(a), in general, directs the Administrator to establish and recover in accordance with sound business principles the cost associated with, among other things, transmission of power. In the specific, section 7(a)(2)(C) directs that transmission rates equitably allocate the costs of the federal transmission system between federal and non-

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[73] *Id.*
[74] 16 U.S.C. §§ 832a(f), 839f(a).
[75] 16 U.S.C. § 832a(f).
[76] Hearing on H.R. 2690 and H.R. 2693 Before the H. Comm. on Rivers and Harbors, 79th Cong. 2 (1945) (statement of Rep. Jackson).

federal power utilizing the system. If Bonneville decides to join the EIM, it will continue to set rates pursuant to the requirements of section 7 of the Northwest Power Act.

5. Joining the EIM Is Consistent with Bonneville's Contractual Commitments

Bonneville's Power Contracts

<u>Position</u>: Bonneville's proposed participation in the EIM is consistent with Bonneville's contractual commitments and obligations under its power sales contracts.

Bonneville does not anticipate any conflicts between its participation in the EIM and its current Northwest Power Act section 5(b)(1) firm requirements power sales contracts that were offered and executed in 2011 as Regional Dialogue Contract High Water Mark (RD CHWM) contracts. The EIM is a within-hour balancing market in which Bonneville's participation would be voluntary, not mandatory, meaning that Bonneville will have the choice of whether to bid surplus power not otherwise committed to meet existing contract obligations into that market.

Bonneville's RD CHWM requirements power sales contracts are of three types: i) load following contracts, which are hour ahead prescheduled contracts for firm power to meet the hourly firm load of the customer; ii) Slice/Block contracts, which are hour ahead prescheduled contracts for calculated planned amounts of power scheduled by the customer for the upcoming hour; and iii) Block only contracts, which are hour ahead prescheduled contracts for planned fixed amounts of power scheduled by the customer for the upcoming hour. Since Bonneville's obligation is determined in the hour ahead of the delivery hour, Bonneville will have set its generation requirement to meet the total of these anticipated planned amounts of power and actual hourly demand for load following for the upcoming hour. Bonneville will ensure that it has met its contractual obligation to deliver power to its customer for the next hour before Bonneville allows the EIM to dispatch any amount of additional power available for that hour.

In addition, Bonneville will continue to maintain sufficient capability to cover any real time load excursions of its load following customers during an hour. Bonneville's Slice/Block and Block only purchasers do not have an ability to change their planned amounts of scheduled power during the hour of delivery. Bonneville's power obligation to these customers during a delivery hour is not subject to change once it has been set by the customer and Bonneville. Therefore, Bonneville's ability to meet its load obligations under the aforementioned contracts will not be affected by its bids into the EIM during an hour.

It should be noted that although Bonneville's RD CHWM contracts contain a provision on resource adequacy, that provision utilizes a multi-year long-term planning standard, and should not be confused with the resource sufficiency tests in the EIM.[77]

Bonneville's Transmission Contracts

Position: Bonneville expects to make EIM-related changes to its Tariff to accommodate its EIM participation. For Tariff service contracts, such changes will be adopted pursuant to the statutory process. For non-Tariff service contracts, Bonneville will seek to implement these changes via mutual agreement with individual customers. Bonneville has not identified any needed modifications to such contracts at this time.

Bonneville expects to make several EIM policy decisions through iterative stakeholder processes prior to its final decision to join the EIM. As described in section III.b.4., implementation of these EIM policy decisions will require Bonneville to add certain EIM-related terms and conditions to its Tariff, business practices, and rates schedules, which Bonneville will consider pursuant to its statutory processes.[78] Any revised Tariff terms and conditions and rates adopted by the Administrator in these proceedings will apply to all of Bonneville's new and existing Tariff-service contracts.

With regard to Bonneville's non-Tariff service contracts (*e.g.*, legacy transmission service agreements), Bonneville has not identified any agreements that would be incompatible with Bonneville's participation in the EIM at this stage of analysis. However, Bonneville will continue to monitor its portfolio of transmission-related contracts through each EIM policy determination to evaluate whether any amendments are necessary and desired for those contracts. If Bonneville does determine that certain EIM-related amendments may be necessary and desired during the course of its EIM decision-making process, it will work with individual customers to pursue any such amendments by mutual agreement.

[77] The CAISO's resource sufficiency requirements are discussed in section III.e.7.

[78] Bonneville will consider EIM-related Tariff revisions in accordance with section 9 of the Tariff, which requires Bonneville to conduct a proceeding in accordance with Section 212(i)(2)(A) of the Federal Power Act and make a final determination in that proceeding. Bonneville will consider EIM-related rate revisions to transmission and ancillary and control area services rate schedules during the BP-22 rate proceeding, which is a proceeding conducted in accordance with section 7(i) of the Northwest Power Act.

6. FERC Jurisdiction with Respect to Bonneville as an EIM Entity

Position: Bonneville's participation in the EIM will not change or enhance FERC's limited authority over Bonneville.

The Federal Energy Regulatory Commission (FERC) has limited authority over Bonneville's marketing activities. The Federal Power Act gives FERC general jurisdiction over the transmission of electric energy in interstate commerce and wholesale sales of electric energy in interstate commerce.[79] Though FERC has general authority to regulate public utilities engaged in interstate commerce, the Federal Power Act specifically exempts governmental entities from FERC's general jurisdiction unless the statute specifically states otherwise.[80] As a federal power marketing administration, Bonneville falls within this exemption.

The Federal Power Act does contain specific provisions that vest FERC with limited jurisdiction over Bonneville. However, neither Bonneville's agreement to participate in the EIM via contract nor the CAISO's status as a FERC-jurisdictional market can create FERC jurisdiction over Bonneville that Congress has not granted by statute. As discussed in section I.b, Bonneville's participation in the EIM would be facilitated via a series of contracts between Bonneville and the CAISO, and will include changes to both entities' Tariffs. Though Bonneville's assent to the agreements that are necessary to facilitate EIM participation may implicate FERC's limited jurisdiction over Bonneville, FERC maintains these limited authorities over Bonneville irrespective of whether Bonneville participates in the EIM. Moreover, Bonneville's voluntary participation in a FERC-jurisdictional market—the CAISO and, by extension, the EIM—would not alter the scope of FERC's authority over Bonneville.[81]

Because the EIM is a FERC-jurisdictional market, the CAISO must file and seek FERC approval of its Tariff, rates, and certain contracts under sections 205 and 206 of the Federal Power Act.[82] These provisions would also capture the contracts that the CAISO and Bonneville will enter into to facilitate Bonneville's participation in the EIM. It is possible

[79] 16 U.S.C. § 824(b)(1).
[80] Section 201(f) of the FPA largely exempts Bonneville from regulation under the FPA because Bonneville is an "agency, authority, or instrumentality" of the United States. Section 201(f) states: "No provision in this subchapter shall apply to, or be deemed to include, the United States . . . or any agency, authority, or instrumentality of any one or more of the foregoing . . . unless such provision makes specific reference thereto." 16 U.S.C § 824(f).
[81] *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 924 (9th Cir. 2005) (The court made clear that FERC cannot expand its statutory authority over an entity based on that entity's voluntary participation in FERC-approved markets.).
[82] 16 U.S.C. §§ 824d, 824e.

that FERC could render a decision on a CAISO filing that Bonneville finds unacceptable. For example, the CAISO could propose, and FERC could approve, a change to its Tariff or rates that is incompatible with Bonneville's statutory directives or strategic goals. If this occurs, Bonneville could remedy the situation by ceasing to participate in the market until the issue is satisfactorily resolved or it may exercise its right to withdraw from the EIM. The EIM is a voluntary market in which members have the unqualified right to withdraw without an exit fee.[83]

7. Market Oversight Under the CAISO Tariff

Position: Joining the EIM would require Bonneville to agree to contractual provisions giving the CAISO certain market oversight and enforcement authority, but Bonneville would retain the autonomy to meet its statutory obligations.

Introduction

Bonneville has considered the effect of granting the CAISO—a nonprofit public benefit corporation organized under and pursuant to California state law—certain oversight and enforcement authority over Bonneville's participation in the EIM. As a general premise, voluntarily submitting to the authorities, oversight, and the potential for sanctions and penalties within the CAISO Tariff does not infringe on Bonneville's authority. Bonneville's participation is voluntary. If Bonneville chooses to participate, then it will be subject to the conditions of participation.

More specifically, under the CAISO Tariff, EIM participants agree to certain oversight by the CAISO Board of Governors and the EIM Governing Body, the market monitoring rules administered by the Department of Market Monitoring (DMM), and recommendations to the CAISO CEO and Board of Governors by the Market Surveillance Committee (MSC). EIM participants must comply with section 29 of the CAISO Tariff,[84] which includes rules of conduct,[85] market power mitigation procedures,[86] and other market monitoring authorities.[87] Nonetheless, Bonneville retains the flexibility to determine how its resources will participate during each interval, the ability to withdraw entirely from the EIM, and the right to appeal the CAISO's decisions. These areas are addressed below.

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[83] See EIM Charter § 2.1, which permits EIM Entities to withdraw from the EIM prior to any action that would cause or create an exit fee.
[84] CAISO Tariff § 29.1(b).
[85] *Id.* at § 29.37.
[86] *Id.* at § 29.39.
[87] *Id.* at § 29.38.

CAISO Tariff Oversight and Enforcement Provisions

Rules of Conduct

All EIM participants are subject to the CAISO's Rules of Conduct.[88] The Rules of Conduct establish expected market behavior for participants, provide sanctions for violations, and delineate whether the CAISO or FERC administers certain rules.[89]

The CAISO administers rules regarding reporting generator availability, gaining approval for generator outages, providing accurate and timely settlement data, and providing accurate and timely responses to the CAISO's investigations and audits.[90] The CAISO may impose monetary sanctions for violations of these rules, ranging from $500 to $10,000 per violation. These sanctions vary depending on the duration, severity, and frequency of violations. EIM participants that object to the CAISO's investigations or determinations retain the right to seek review with FERC.[91]

FERC administers the rule regarding EIM participants submitting bids "from resources that are reasonably expected to be available and capable of performing at the levels specified in the [b]id."[92] The DMM reports suspected violations of this rule directly to FERC.[93]

Bonneville has reviewed the Rules of Conduct and generally agrees that they represent conduct that Bonneville would want other participants to abide by. If Bonneville disagreed with how the CAISO chose to apply its authority, Bonneville could seek review with FERC.

Market Power Mitigation

The CAISO monitors the EIM in real-time to identify and prospectively mitigate market conduct that can cause non-competitive constraints.[94] The CAISO will (1) apply real-time market power mitigation procedures to the EIM, including transfer constraints into an EIM Entity balancing authority area; (2) conduct competitive path assessments for each EIM Entity balancing authority area; (3) perform locational marginal price decomposition for

[88] *Id.* at § 29.37. Note that certain rules of conduct related to Operating Instructions are inapplicable to EIM participants. *Id.* at § 37.2.
[89] *Id.* at § 37.
[90] *Id.* at § 37.1.5.
[91] *Id.* at §§ 37.6.4, 37.8.10.
[92] *Id.* at §§ 37.1.5, 37.3.1.1.
[93] *Id.* at § 37.8.2.
[94] *Id.* at § 39.1.

each EIM Entity balancing authority area; and (4) determine default energy bids for EIM Participating Resources.[95]

Ahead of each interval, the CAISO conducts transmission path assessments for each EIM Entity balancing authority area to determine whether a path is competitive or non-competitive.[96] If the CAISO finds that a transmission path is non-competitive, it will employ local market power mitigation to relieve the identified constraint. Any resource dispatched to relieve congestion on a non-competitive path is subject to the CAISO's market mitigation procedures.[97] Mitigated resources will receive the higher of either: (1) a CAISO-determined "default energy bid," which is generally pegged to a cost- or market-based reference level; or (2) a competitive proxy price, which is an estimate of what the price would be in the absence of the non-competitive constraint.[98] The CAISO may also report an EIM participant to FERC as part of its market power mitigation procedures.[99]

As explained in section III.e.5, Bonneville has reviewed the CAISO Tariff's market power mitigation procedures and has been actively involved in the CAISO's development of a fourth default energy bid that recognizes the unique characteristics of hydro generating resources. Adding the fourth default energy bid criteria to the CAISO Tariff should alleviate Bonneville concerns regarding market power mitigation.

Other Market Oversight

The DMM is an independent market monitoring unit, as required in all organized markets.[100] The DMM identifies and advises the CAISO Board of Governors on market design flaws, potential market rule violations, and market power abuses.[101] The CAISO's definition of market violations is broad, including a CAISO Tariff violation; a violation of a FERC-approved order, rule, or regulation; market manipulation; or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.[102] If the DMM identifies a violation, it will refer alleged market violations to the CAISO or directly to FERC, depending on the nature of the violation.

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[95] *Id.* at § 29.39.
[96] *Id.* at § 39.7.2.
[97] Price Formation in Organized Wholesale Electricity Markets: Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets, FERC, § 3.3 (Oct. 2014), *available at* https://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf.
[98] CAISO Tariff § 39.7.1.
[99] *E.g., id.* at § 39.4.
[100] *See Wholesale Competition in Regions in Organized Electric Markets,* Order No. 719, 7 FERC Stats. & Regs. ¶ 31,281, at P 326 (2008).
[101] CAISO Tariff § 29.38 and Appendix P § 1.
[102] *Id.* at Appendix A.

The CAISO Tariff also establishes the Market Surveillance Committee (MSC) to provide market design and monitoring advice to the CAISO.[103] The MSC submits recommendations directly to the CAISO CEO and the Board of Governors based on data collected by the CAISO and the DMM. Unlike the DMM, the MSC is comprised of external members and operates independently from the CAISO. The CAISO is required to publish MSC reports and recommendations upon the MSC's request. Further, the Tariff requires the MSC to review and comment on DMM analyses and reports.[104] The MSC can recommend that the CAISO impose sanctions and penalties for Tariff violations, but has no authority to impose punitive measures itself.

In addition, if the CAISO identifies potential market abuses that are outside of the market power mitigation procedures in section 39 of its Tariff, the CAISO can make a Section 205 filing under the Federal Power Act[105] to petition FERC for authorization to apply appropriate mitigation measures.[106]

While Bonneville could be subject to these investigations, Bonneville supports independent entities with specific expertise reviewing market activity and looking for potential improvements. These provisions protect Bonneville by identifying and resolving potential bad behavior by other EIM entities. The CAISO Tariff does not give the DMM, the MSC, or the CAISO the ability to direct Bonneville's operations. Instead, they seek to ensure that the market functions properly and that all market participants follow the conditions of participation.

Conclusion

Bonneville would be subject to the terms of the CAISO Tariff applicable to the EIM and its associated market rules, if it joined the EIM. These provisions are reasonable to ensure the market functions properly. These provisions would not undermine Bonneville's ability to meet its statutory obligations, including its ability to operate its system to meet non-power requirements. Existing EIM rules do not require participants to bid a specified amount of generation into the EIM, nor does the CAISO assume control of the participants' transmission systems to facilitate EIM transfers.[107] Instead, the EIM depends on voluntary bids and the transmission capacity that participants make available to the market. This preserves Bonneville's autonomy over how it sells power and provides transmission service under its statutes. Further, Bonneville would retain the ability to withdraw from

[103] *Id.* at Appendix O.
[104] *Id.* at Appendix O § 5.
[105] 16 U.S.C. § 824d.
[106] CAISO Tariff § 39.1.
[107] *See* section III.b.1 for further discussion on Bonneville's authority to sell power into the EIM.

the EIM. Under Section 2.1 of the EIM Charter, the EIM Governing Body cannot impose a penalty or exit fee on participants that choose to withdraw from the EIM without first providing notice to participants and allowing them to exit. Voluntary participation is fundamental to Bonneville's ability to join the EIM.

8. EIM Governance

<u>Position</u>: Bonneville can participate in the EIM under the current governance structure, but there may be an opportunity to improve the structure.

The current governance structure of the EIM does not present a barrier to Bonneville's participation in the EIM. However, Bonneville believes that the structure can be improved. The CAISO has initiated a public stakeholder process to review the EIM governance structure. Bonneville is actively participating in this process and will continue to advocate for a more diverse, independent, and durable EIM governance structure. Moreover, Bonneville will evaluate any future EIM governance proposals to ensure they accommodate Bonneville's status as a federal power marketing administration and do not interfere with its ability to perform its statutory and contractual obligations.

<u>EIM Governance Framework</u>

Pursuant to Article IV of the CAISO bylaws, the CAISO Board of Governors[108] constituted the EIM through a foundational charter, which establishes the EIM Governing Body, its responsibilities, and procedures.[109] In general, the Charter for Energy Imbalance Market Governance (EIM Charter) lays the framework for EIM governance and tasks the EIM Governing Body with promoting, protecting, and expanding the EIM. All new EIM Governing Body members are selected by the EIM Nominating Committee—comprised of representatives from various stakeholder sectors within the EIM footprint—and approved by the existing EIM Governing Body.[110] All EIM Governing Body members must be independent of CAISO market participants and stakeholders.[111]

[108] The CAISO Board of Governors is responsible for designing and overseeing the CAISO-controlled grid. The California governor appoints and the senate confirms each board member. Amended & Restated Bylaws of CAISO, § 4.1 (Dec. 18, 2015), *available at* http://www.caiso.com/Documents/ISOCorporateBylaws_amendedandrestated_.pdf (CAISO Bylaws).

[109] *See* CAISO Bylaws, Art. IV (establishing the EIM Governing Body).

[110] EIM Charter § 1.2; *see also* Selection Policy for the EIM Governing Board Selection Policy, CAISO (rev. Nov. 28, 2016), *available at* https://www.westerneim.com/Documents/SelectionPolicy_EIMGoverningBody.pdf.

[111] EIM Charter § 1.1.2.

EIM Policy Decision-making

The EIM Charter delegates decisional authority to the EIM Governing Body over certain real-time market rules and limits the authority of the CAISO Board of Governors over such rules. As discussed in section I.b, the EIM Charter delineates the scope of this authority based on whether the real-time market rule is EIM-specific or broadly applicable to all CAISO market participants. Specifically, the EIM Governing body has primary authority over all market rules that apply uniquely to EIM balancing authority areas.[112] The EIM Charter also limits the CAISO Board of Governors' authority to enact market rule changes that are within the EIM Governing Body's primary authority by requiring prior approval of such changes by the EIM Governing Body.[113] The CAISO Board of Governors retains authority over all other real-time market rules, but the EIM Governing Body is authorized to provide formal input to the CAISO Board of Governors on those matters.[114] With respect to substantive changes to the EIM Charter, the CAISO Board of Governors may only approve such changes after they are first presented to the EIM Governing Body for advisory input.[115]

Ideally, the EIM governance would be completely independent from the CAISO Board of Governors, which are appointed by the Governor of California, but Bonneville does not see the current EIM policy decision-making paradigm as a barrier to its participation in the EIM. As described in section III.a.3, the EIM is a voluntary market. The EIM does not alter Bonneville's decision-making authority over the dispatch of generation or the operation of the federal transmission system. Moreover, EIM entities also retain unqualified withdrawal rights. If the EIM Governing Body and the CAISO Board of Governors approved an EIM market rule change that interfered with Bonneville's ability to meet its statutory or contractual obligations, Bonneville could cease its participation in the EIM until the matter is satisfactorily resolved or exit the market entirely.

EIM Governance Review

Section 2.2.4 of the EIM Charter directs the EIM Governing Body to initiate a public process to re-evaluate the current EIM governance structure no later than September 2020.[116] This

[112] *See also* Guidance for Handling Policy Initiatives within the Decisional Authority or Advisory Role of the EIM Governing Body, CAISO (rev. Mar. 27, 2019), *available at* https://www.westerneim.com/Documents/GuidanceforHandlingPolicyInitiatives-EIMGoverningBody.pdf.
[113] EIM Charter § 2.2.
[114] *Id.*
[115] *Id.* at § 8.
[116] *Id.* at § 2.2.4.

re-evaluation of the EIM is currently underway.[117] As noted in section I.b, the CAISO's most recent proposals call for the establishment of a stakeholder-comprised committee to develop a governance proposal(s) through an iterative public process, which would then be presented to the EIM Governing Body and CAISO Board of Governors for approval.[118] Bonneville has actively engaged in each successive public stakeholder process since the EIM Governing Body initiated its EIM governance review process. Bonneville plans to continue monitoring and participating in this initiative as it moves forward to ensure any future revisions to the EIM governance structure continue to respect Bonneville's federal status and do not interfere with Bonneville's ability to meet its contractual and statutory obligations.

c. Environmental Obligations

Proposal: Based on its most current assessment, Bonneville believes signing the Implementation Agreement is likely the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. Bonneville solicits comments from stakeholders on this proposal.

Bonneville's role is to market and transmit the power generated by the Federal Columbia River Power System (FCRPS) projects in accordance with Bonneville's statutory directives to meet power customer loads and provide an adequate, efficient, economical, and reliable power supply. The FCRPS operations are managed with other project purposes and system-wide operating constraints, including operations to support Endangered Species Act (ESA)-listed fish. 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.

Bonneville is considering the potential environmental effects that could result from its proposal to enter into the EIM Implementation Agreement, consistent with the National Environmental Policy Act (NEPA). Based on its most current assessment, Bonneville believes this proposal is likely the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. Nonetheless, Bonneville is still assessing the proposal and, depending upon the ongoing environmental review, may instead issue another appropriate NEPA document.

[117] *See* EIM Governance Review: Issue Paper and Straw Proposal, CAISO (Dec. 14, 2018), *available at* https://www.westerneim.com/Documents/IssuePaperandStrawProposal-EIMGovernanceReview.pdf.
[118] *See* EIM Governance Review: Draft Final Proposal for Formation of an EIM Governance Review Committee, CAISO (May 21, 2019), *available at* https://www.westerneim.com/Documents/StrawProposal-EnergyImbalanceMarketGovernanceReviewCommitteeFormation.pdf.

Bonneville will complete its NEPA process and issue its NEPA documentation for this proposal prior to Bonneville issuing its Record of Decision for the proposal.

All public comments concerning NEPA compliance and/or potential environmental effects for this proposal that Bonneville received during the stakeholder discussions are being reviewed as part of this NEPA process.[119] Bonneville also will consider any public comments received on this topic as part of the 30-day public comment period associated with this Proposal.

d. Business Case for Joining the EIM

Position: Bonneville's proposal to join the EIM is a sound business decision. Bonneville expects that joining the EIM will produce both net quantitative benefits and qualitative benefits. The quantitative benefits include positive additional net annual revenue of $29-34 million. By joining the EIM Bonneville also expects numerous transmission benefits that would be difficult or costly to realize on their own. The EIM is able to provide compelling operational and commercial benefits that will enhance Bonneville's ability to more efficiently and effectively manage the FCRTS.

1. Background and Context

Since the beginning of the EIM in 2014, the CAISO has published quarterly benefit reports outlining the benefits of the EIM.[120] As of April, 2019, the reported collective gross benefits of the EIM exceeded $650 million in savings to regional EIM Entities.[121]

Bonneville recognizes that its position in the EIM will be unique. Bonneville brings to the EIM different legal mandates, a large transmission system, and a system mix almost exclusively reliant on hydro-electric power. Bonneville also acknowledges that these reports do not include the costs of joining the EIM.

To evaluate the business case of joining the EIM, Bonneville developed a cost-benefit analysis (C/B Analysis), that considers qualitative benefits and compares estimated startup and annual costs to expected annual benefits. For qualitative benefits, Bonneville considered the operational benefits of the EIM. These benefits primarily inure to the transmission system, with better congestion management, improved controls, greater state awareness, and better modeling and coordination. The C/B Analysis, which Bonneville

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[119] No NEPA-related comments have been received to date.
[120] *See* Western Energy Imbalance Market, *available at* https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[121] *Id.; supra* section I.a.

developed with input from regional stakeholders, is provided in Attachment B to this letter. A summary of the C/B Analysis and Bonneville's findings is provided in section III.d.2 below.

Bonneville presented its initial findings at a stakeholder meeting on May 15, 2019.[122] On June 12, 2019, Bonneville presented updated analysis to stakeholders at a public meeting in response to stakeholder feedback requesting additional scenario analysis.[123]

2. Costs and Benefits Analysis Summary

i. Costs of Joining the EIM

Joining the EIM will result in changes to the internal operations and systems for Bonneville's Power Services and Transmission Services. Because these changes are expected to occur across the business lines, Bonneville approached the cost element of the Cost Benefit Analysis from a "One BPA" method and did not attempt to assign costs to a particular business line. To assist in developing estimates for the costs of joining the EIM, Bonneville engaged Utilicast, a consulting services firm that specializes in the energy and utilities industry. Utilicast provided Bonneville estimates for a variety of Grid Modernization projects in 2017. After determining which projects were essential for EIM participation, Bonneville reviewed and updated Utilicast's estimates to incorporate Bonneville's EIM-related knowledge. Additionally, Bonneville internally estimated ongoing costs associated with Bonneville participation.

Start-Up Costs

Start-up costs are the costs that Bonneville expects to incur in the initial period leading up to and just after joining the EIM.

As noted earlier, Bonneville is in the process of modernizing the federal power and transmission systems. Many of the upgrades and system improvement needed for that effort also support the technological or operational requirements for joining the EIM. To isolate the incremental costs of joining the EIM, Bonneville focused its cost analysis on spending that Bonneville would only undertake if Bonneville were to join the EIM. Bonneville determined the "EIM Incremental" nature of each project and made updates to initial Utilicast cost estimates where appropriate. These costs generally fall into three

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[122] Materials from the meeting are available at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190515-May-15-2019-EIM-Stakeholder-Mtg.pdf.
[123] Materials from the meeting are available at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190612-June-12-2019-EIM-Stakeholder-Mtg.pdf.

broad groups: infrastructure (*e.g.*, metering and AGC modernization), operations (*e.g.*, base schedule submission and bid curve development), and after-the-fact (*e.g.*, settlements). Infrastructure costs are provided as a range to reflect the uncertainty around the need for metering interchange upgrades.

Bonneville's estimated startup costs, including labor and non-labor costs, are as follows:

Startup Costs ($M)

EIM Category	Cost* ($M)	Labor	Non-Labor
Infrastructure (Metering & AGC Modernization)	$7.9-$13.3	$2.7-$8.1	$5.3
Operation (EIM Integrator, Schedule Submission, & Bid Curves)	$17.2	$9.8	$7.4
After-the-Fact (Settlements)	$4.6	$3.6	$1.0
Total	**$29.7-$35.1**	**$16.1-$21.5**	**$13.7**

Bonneville's startup costs are higher than many other entities' startup costs but commensurate with Bonneville's relative size, complexity, and existing infrastructure. It is also important to note that a portion of Bonneville's labor costs included in the startup cost estimate are not expected to be incremental to Bonneville as a whole. CAISO implementation fees of $1.8 million are included in startup costs.

On-Going Costs

If Bonneville joins the EIM, Bonneville would also experience certain on-going costs. The estimates of the on-going EIM costs have evolved as Bonneville has increased its understanding of the EIM. Bonneville subdivided on-going costs into the same three categories as the start-up costs: infrastructure, operations, and after-the-fact. There are no ongoing costs categorized as Infrastructure because expected O&M for new systems is categorized as Operation. Operational costs include estimates of the annual internal costs to perform EIM-related functions, such as creating and submitting resource plans, staffing and developing a new EIM desk, maintaining Information Technology (IT) systems, and the costs of CAISO fees related to EIM participation. After-the-fact costs include costs of maintaining more settlements staff.

The estimated on-going costs of the EIM are as follows:

Ongoing Costs ($M/yr)

EIM Category	Cost* ($M)
Infrastructure	$0.0
Operation (Resource Plans, EIM Desk, IT O&M, CAISO Fees)	$5.7
After-the-Fact (Settlements Staff)	$1.2
Total	**$6.9**

ii. Benefits of Joining the EIM

Overview of the Dispatch Benefit of the EIM

One of the primary benefits the EIM provides to participating entities is the functionality of dispatching generation economically. Consistent with the generator's bids and transmission constraints, the EIM provides a signal to Participating Resources to increase or decrease generation when it is economic. In this way, resources participating in the EIM are likely run by owner/operators as follows: generation increases when doing so will make more revenue for that resource, and generation decreases when it would save that resource money. This feature of the EIM is generally referred to as the "dispatch benefit."

Methodology for Determining the Dispatch Benefit

To estimate the dispatch benefits of joining the EIM, Bonneville contracted with E3, an industry-recognized expert energy consulting firm that performed EIM benefits analyses for many other current or prospective EIM participants. E3 used a PLEXOS modeling approach, which simulates day-ahead and hour-ahead dispatch, along with both the fifteen-minute and five-minute dispatches of the EIM, and explicitly quantifies the incremental dispatch benefits of EIM participation.

Using the PLEXOS model, E3 simulated dispatches of the FCRPS within Bonneville's balancing authority area under two scenarios: (1) a "Business as usual" case (BAU); and (2) an EIM case. E3 used historical data from 2016-2018, including generation and generation forecasts, load and load forecasts, interchange, and price data.

Assumptions Used in Determining Dispatch Benefit

The federal power system is unique in many respects, with specific environmental, statutory, and operational restrictions limiting its flexibility. To ensure that E3's analysis reflected feasible dispatches by the federal system, Bonneville provided a list of parameters that had to be maintained when E3 performed its analysis. Briefly, these parameters were:

1. 24-hour energy neutrality[124] relative to historical actual generation to avoid river management issues
2. System feasible min/max limits calculated by the Slice Computer Application
3. Net of regulation, EIM-dispatchable capacity limited to available INC/DEC spin capacity at Big 10 projects (to eliminate simulated unit starts/stops)
4. All other generation in Bonneville's balancing authority area is held constant in both the BAU case and the EIM case
5. Bonneville estimated Resource Sufficiency requirements

In addition, Bonneville performed additional verifications of E3's proposed dispatches to ensure that the study produced dispatches of federal generation that were feasible. Bonneville evaluated and modified the E3's study for the following:

1. Verified model compliance with all constraints
2. Reviewed simulated dispatch to ensure reasonableness
3. Verified simulated EIM net sales positions are within available transmission expectations
4. Reviewed initial sensitivities (50% volatility & no CA deliveries) and resulting effects
5. Confirmed that historical spin capability was sufficient to pass EIM RS requirements the vast majority of the time
6. 75% success rate applied to offset perfect foresight.[125]

Scenarios

Bonneville presented its initial findings at the May 15, 2019, stakeholder meeting. Subsequently, stakeholders requested that Bonneville perform additional analysis using different pricing assumptions. Bonneville agreed to perform additional analyses and engaged E3 to simulate Bonneville's benefits using individual pricing node scenarios. Bonneville selected the price nodes at PacifiCorp West (PACW), Puget Sound Energy (PSEI), and Portland General Electric (PGE). These price nodes display price levels and volatility

[124] In this context, energy neutrality means the same level of generation over the course of a 24-hour period in both cases.

[125] The E3 study produced results that assumed Bonneville had perfect market foresight (Bonneville bid range perfectly matched prices). Bonneville discounted E3's results by 25% to reflect Bonneville having imperfect knowledge of prices and thus only receiving the dispatch benefits of the EIM 75% of the time. This is not treated as a constraint, because it was an adjustment to benefits after the model completed its simulation.

experienced by actual Northwest EIM participants. Bonneville has determined that the revenue simulations using these price nodes better reflect the dispatch benefits of participating in the EIM. The resulting estimated gross benefits are summarized below.

Sensitivity Analysis

In order to test the robustness of this quantitative dispatch benefits range, Bonneville requested E3 to run its analysis using additional sensitivities based on the midpoint of scenario results (PGE or NW Midpoint/Base).

1. 50% Volatility: A reduction in market volatility that assumes lower intra-hour price volatility by 50%;[126]

2. GHG Cost Avoidance: To reflect no direct California deliveries, and avoid the GHG compliance fee, E3 modeled Bonneville receiving lower LMP when selling during intervals where marginal GHG component is nonzero;[127]

3. Flexible Ramp Sufficiency Test (FRST) Only: To reflect minimal EIM participation, E3's modeling limited Bonneville's participation to only what is necessary to meet estimated resource sufficiency requirements, based on FRST requirements, not including diversity benefit; and

4. Higher Success Rate (90%): To reflect improved foresight on market conditions, hydro constraints, operations, and success in being awarded bids at modeled price.

Summary of Dispatch Benefits

The table below shows E3's estimation of the dispatch benefit to Bonneville of joining the EIM. This table reflects the annual incremental revenue Bonneville would have received above the "business as usual" case had the EIM been in place under the operational and hydrological conditions that existed during the 2016 through 2018 period.

[126] A larger number of EIM participants bringing both supply and demand to the market is expected to reduce observed volatility in EIM prices. A 50% reduction is not a forecast, but a scenario meant to incorporate potential lower volatility in the future.
[127] Bonneville does not currently have a procedure in place to allow delivery to CA in an EIM construct due to its inability to pay a GHG compliance fee. This scenario reflects lower market benefits associated with preventing delivery to CA. The carbon issue is explained in section III.e.4 of this document.

Gross EIM Benefits ($M/yr)

	Estimated Gross Revenue
Range of Gross Dispatch Benefits	**$36-40**
PSEI Price	$36.1
PACW Price	$40.4
PGE Price (NW Midpoint/Base)	$39.2

Gross EIM Benefits Sensitivities ($M/yr)

Reduced Volatility	$35.3
GHG Compliance	$34.6
FRST-Only Participation	$24.4
Higher Success Rate	$47.1

iii. Net Benefit of Joining the EIM

Comparing the costs of joining EIM with the modeled net dispatch benefits indicates significant *annual* net financial benefits to Bonneville if it participates in the EIM.

Net EIM Benefits ($M/yr)

	Estimated Net Revenue
PSEI Price	$29.2
PGE Price	$32.3
PACW Price	$33.5

Bonneville recognizes that the annual net EIM Benefits do not account for startup costs, as discussed above.

E3 modeling, paired with estimates of startup and ongoing costs, suggests that EIM participation would quickly pay for itself based solely on dispatch benefits. The sensitivities that were evaluated did not fundamentally change this conclusion.

The results of Bonneville's benefits analysis are set forth in Attachment B. Comments on these results should be made in response to this Proposal.

iv. Transmission Benefits

Background and Context

The EIM not only produces the most economical dispatch of voluntarily offered resources to serve load and imbalance across the entire EIM footprint,[128] it does so while simultaneously honoring all modeled constraints.[129] The EIM models numerous constraints, including transmission operating limits, balancing authority area power balance, interchange transfer limits, ramp rates of resources, minimum and maximum resource generation limits, and many others that are too numerous to list here.

The EIM produces 15-minute solutions for up to the next two hours and 5-minute solutions for up to the next hour based on a large set of input data. This includes a full state-estimated network model of the Western Interconnection, planned and forced outages, load forecasts, variable energy forecasts, economic resource offers, transmission limits, generation limits, and generation ramp rates, among many other data inputs. As such, the EIM is able to respond to not only real-time conditions but also predict future needs and operating conditions in advance.

Qualitative Transmission Benefits

The EIM can provide numerous qualitative benefits due to how the EIM works, the large amount of data it requires, and the information that it produces. Qualitative benefits categories include improved control, improved state awareness, modelling and coordination, and transmission investment decisions. Below, each category of qualitative benefits is described in more detail.

Improved Controls:

- Proactive congestion management – Transmission constraints modelled and enforced in the EIM will identify congestion before it arises and dispatch least cost resources to stay within operating limits.
- Reactive congestion management – The EIM can resolve congestion that occurs in real-time or is the result of an unplanned or forced outage within one or two 5-minute market intervals.

[128] The EIM footprint (a.k.a. EIM Area) includes all participating balancing authority areas plus the CAISO.
[129] The EIM is said to be "Security Constrained" in that it honors modeled constraints in the process of producing the most economical solution to serve load and imbalance. The combination of the economic dispatch and the security-constrained nature of the EIM are often referred to as Security-Constrained Economic Dispatch (SCED).

- <u>Proactive voltage control</u> – The Rate of Change constraint, which helps ensure the EIM does not adversely impact voltage, would likely be more effective by including incremental dispatches from Bonneville area resources.
- <u>Higher Transmission Utilization</u> – With the more advanced, responsive, and foreword looking congestion management capabilities of the market, there is the potential to more fully utilize existing transmission assets.

Improved State Awareness:

- <u>Situational awareness</u> - Leveraging the increased and more accurate data the EIM provides will allow Bonneville to create new and improved state awareness displays, allowing operators to better predict emerging operational issues.
- <u>Access to CAISO EIM Dispatcher tools</u> – the CAISO's Automated Dispatch System and Balancing Authority Area Operations tool will allow Bonneville Transmission to review dispatches, ensure dispatch accuracy, view Adjusted Net Scheduled Interchange, have Manual Dispatch functionality, view resource deviations, and view Bonneville binding transmission constraints.

Modeling and Coordination:

- <u>Improved network modeling</u> – Results in improved sharing and fidelity of critical reliability data and models.
- <u>Improved outage coordination</u> – Reduces the communication and coordination latency of outage information, which can result in temporary differences in modeled outages.
- <u>Improved Power & Transmission coordination</u> – More so than today, participating in the EIM requires tighter and more effective coordination of resource capabilities to ensure that Resource Sufficiency (RS) tests are passed and that Bonneville has reliable and economic outcomes.

<u>Transmission Investment Decisions</u>

The congestion management features of the EIM are expected to be more economically efficient, precise, and effective than present curtailment and bilateral redispatch capabilities. Further, through the congestion component of LMPs, over time the EIM can also help identify areas of the system that might benefit from transmission investments. This should create new opportunities for optimizing transmission expansion investment decisions as well as improve day-to-day operation of the power system. The types of projects that the EIM could help defer or avoid are the transmission expansion projects that are driven by network congestion that could be remediated with security-constrained economic dispatch. These include potentially capital intensive projects like the I-5 Corridor Reinforcement that target network flowgates with dispatchable generation on both sides. The deferral or avoidance of such projects can result in significant long-term cost savings to Bonneville transmission customers.

There are some other categories of capital projects that are driven by other needs that the EIM would not be expected to displace, such as:

- Sustain Program - These projects are needed to ensure continued safe and reliable operation of existing facilities, such as replacement of wood poles or transformers that have reached their end of life use.
- Generation Interconnection, Line & Load Interconnection - These Expansion Program projects are driven by requests from customers that need new access to the grid, such as new wind generators or data center loads.
- Load Service Area reinforcements - These projects are required to mitigate reliability criteria violations that could lead to load loss following outages. Often there is little or no additional resource capacity to increment within the load pockets during peak load conditions. An example is the Hooper Springs project in southeast Idaho.

Transmission Curtailments

When Bonneville determines that transmission flow relief is necessary to maintain system reliability, Bonneville may curtail transmission schedules pro-rata according to NERC Curtailment priority. Curtailments are non-optimal, as more MW of schedules typically must be curtailed to attain the desired MW of flow reductions. This inefficiency can be attributed to a number of factors such as Bonneville only being able to curtail schedules where it is the Transmission Service Provider or Transmission Operator; any potential relief is highly dependent on the source and the sink of the underlying schedules. Further, curtailments result in imbalances that need to be resolved separately by each impacted balancing authority area, often further reducing the effectiveness of curtailments, because each balancing authority area's resolution of the imbalance resulting from the curtailment is typically not informed by Bonneville's transmission constraints.

The EIM's security-constrained economic dispatch (SCED) model is able to find an optimal redispatch solution of voluntarily offered resources that can simultaneously minimize costs while taking into consideration transmission constraints and operating limits. Price signals and market dispatches incentivize effective resources to be dispatched (incremental or decremental) to manage the congestion in the most cost effective manner possible while simultaneously ensuring each EIM participating balancing authority area remains balanced.

Since any effective and economic EIM Participating Resource can potentially fulfill the market dispatches, the EIM has the potential of reducing the burden on Bonneville transmission customers and reduce the likelihood of curtailments or scheduling restrictions.[130]

As an example of the ability of the EIM to provide moderate amounts of flow relief, Bonneville tested the EIM Area Total Flow (ETF) constraint that was created as part of the Bonneville-CAISO Coordinated Transmission Agreement (CTA).[131] Bonneville compared the effectiveness of the EIM to provide flow reductions versus traditional schedule curtailments. The ETF constraint was able to provide in one 5-minute market run an amount of flow relief that would have required over 1,200 MW of schedule curtailments.

EIM as a Non-Wires Solution

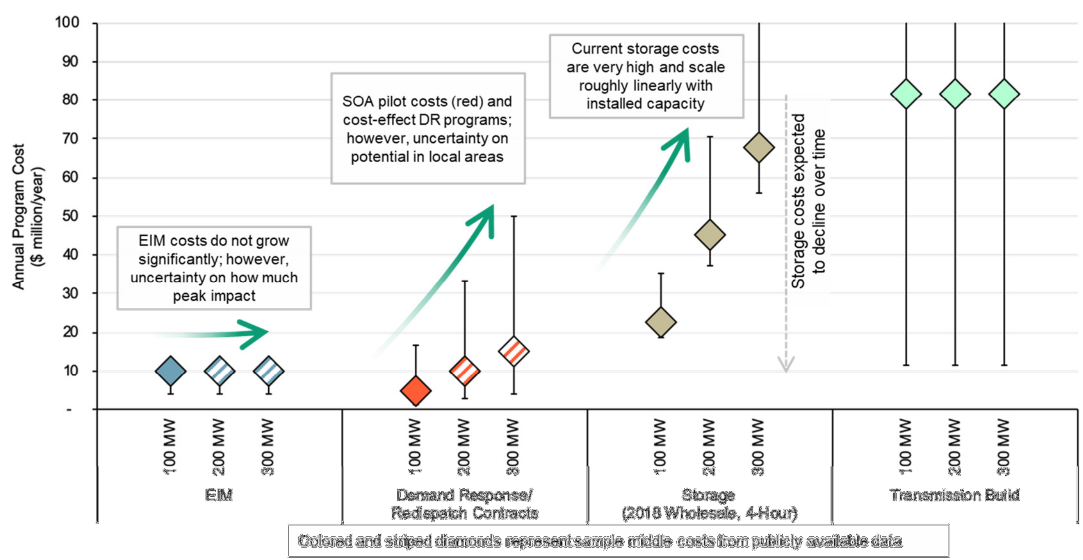
The EIM has characteristics that Bonneville believes could be used as a cost effective alternative for managing moderate amounts of intra-hour congestion across the transmission system. These characteristics are akin to Bonneville's use of non-wires solutions to address congestion. The characteristics of the EIM compared to demand response (DR), storage, and transmission builds are shown in the table below.

	EIM	DR	Storage	Transmission Build
Generation Capacity Value	No	Yes	Yes	No
Energy Value	Yes	Yes	Yes	No
Transmission Capacity Value	Low	Low	Medium	High
Congestion Area	Wide	Local	Local	Local
Congestion Value	High	Medium	Medium	High
Effort to Provision	Low	Medium	Medium	High
Levelized Costs	$	$$	$$$	$$
Call Option Timing	N/A	0-2 Days	0-2 Days	N/A
Response Time	8-12 Minutes	0-18 Hours	0-18 Hours	N/A
Duration	5-240 Minutes	1-360 Minutes	1-480 Minutes	30-50 Years
Uses	Load Service Imbalance Energy Economic Dispatch Congestion Management Renewable Integration Energy Optimization	Load Service Peak Shaving Congestion Management Renewable Integration Ancillary Services	Load Service Peak Shaving Congestion Management Renewable Integration Ancillary Services Energy Optimization	Load Service Renewable Integration

130 Transmission rights remain unchanged by the EIM.
131 The CTA is available at https://www.bpa.gov/transmission/CustomerInvolvement/CoordinatedTransmissionAgreement/.

Bonneville will continue to invest in transmission builds, DR, and storage as part of Bonneville's resource planning and load service strategies.[132] However, the EIM can provide Bonneville an additional tool to help manage intra-hour congestion across a wide area (*e.g.*, multiple constraints or locations) with minimal incremental costs, whereas other solutions are typically a locational solution and applicable to only portions of the system. For example, additional locational investments in DR, storage, or transmission builds would potentially be required to manage flows across multiple wide area constraints. All of these types of solutions will still be necessary if Bonneville joins the EIM, but Bonneville would be able to incorporate less expensive and simpler redispatch options in certain situations that may be very difficult or cost prohibitive for Bonneville to achieve outside of joining the EIM.

The figure below shows conceptually how the EIM costs[133] do not grow significantly as flow relief needs increase (100 MW, 200 MW, 300 MW), although uncertainty on how much flow relief is available increases with need. For illustrative comparison, utilizing DR or storage would require additional investments as more flow relief is needed or additional areas of the system need flow management.[134]



[132] The EIM does not provide any energy capacity or transmission capacity value and cannot be relied upon to meet hourly resource sufficiency or long-term resource adequacy needs. Investments in resources and transmission assets with true capacity value will still be necessary.
[133] EIM costs are illustratively shown as annual levelized program costs based on Bonneville's estimated startup and ongoing costs spread over 20 years at an 8% discount rate to be roughly $10 million/year.
[134] Comparison costs depict up-front implementation costs, not levelized or discounted over the anticipated life of the solution. Bonneville expects that the levelized costs of an ongoing DR program would be significantly less than those from the time-limited SOA pilot. While the cost of storage solutions has rapidly declined in recent years, with further cost reductions expected, figures shown here may not represent near-horizon costs for battery storage.

Illustrative Quantitative Example

Accurately and objectively quantifying EIM transmission benefits is challenging given the multi-faceted nature of the EIM and that Bonneville will have many options that must be considered and evaluated when making future investments in solutions to address operational and reliability needs.[135] However, it is useful to compare an illustrative quantitative scenario made possible by joining the EIM to one or more non-wires scenarios.

Assuming two flowgates, each needing 100 MW of intra-hour flow relief, one can develop an illustrative quantitative example as follows:

- Battery and Redispatch Scenario: Assume that the relief comes from a 50/50 mix of battery storage and Redispatch contracts or DR
    - Assume Redispatch/DR costs based on South of Allston (SOA) Redispatch Pilot[136]
- EIM: Based on total levelized EIM program costs

As shown below, the annual costs would be $27.6 million/year in the Battery and Redispatch scenario and $10 million/year in the EIM case. The annual program costs for the Battery and Redispatch scenario would be expected to increase if more relief is needed or more flowgates need to be managed, whereas the EIM costs would likely not grow significantly. For example, as a sensitivity, if you changed the base scenario to 4 flowgates or 200 MW, the annual program costs would be $55.2 million/year in the Battery and Redispatch scenario and $10 million/year in the EIM case.

Battery and Redispatch Scenario		EIM Case	
100 MW battery @ $226/kW-year	$22.6 million/year	$10 million/year (levelized startup and ongoing costs)	$10 million/year
100 MW Redispatch Contract / DR @ $50/kW-year	+ $5.0 million/year		
Annual Cost	**= $27.6 million/year**		**= $10 million/year**

[135] DR, storage, and transmission builds have unique purposes and value outside of congestion management.
[136] The SOA Redispatch Pilot provided for approximately 100 MW of flow relief for 40 hours/year *(10 events, 4 hours each, weekdays afternoons only, from July-September, 2017 and 2018)* from 200 MW of incremental and 200 MW of decremental capacity with a prior to pre-schedule call-option requirement and manual deployments. A longer-term program may have been less expensive on an annual basis (*e.g.*, 5-7 years).

Transmission Benefits Summary

The EIM has characteristics that Bonneville believes provide many qualitative transmission benefits and is an additional tool for Bonneville to use for grid management. Further, Bonneville's transmission customers in its balancing authority area may also benefit by being able to bid their resource flexibility into the EIM, allowing them an additional opportunity to optimize their energy dispatch and maximize the value of their resources.

The EIM not only provides the most economic dispatch solution to supply load and imbalance in the balancing authority area, it can also provide a more precise, effective, and cost efficient mechanism to manage moderate amounts of intra-hour congestion. While the EIM does not create new capacity or replace the need for investments in transmission, DR, or storage, it is a complementary low cost alternative (among other non-wires options as well as new transmission builds) for addressing modest intra-hour transmission relief needs that arise across the Bonneville system.

Comments on the transmission benefits should be made in response to this Proposal.

e. EIM Policy Proposals

As explained in section III, Bonneville is proposing decisions on several policy matters to be decided in the September 2019 ROD. These policy matters are:

1. Generation Participation Model
2. Transmission Usage – Interchange
3. System Operations Tools
4. Carbon Obligations and related considerations
5. Market Power (LMPM and DEB)
6. Load Aggregation
7. Resource Sufficiency – Balancing Authority Area Level

1. Federal Generation Participation Plan

Proposal: *Bonneville will initially participate in the EIM with federal hydroelectric dams aggregated into three resource zones comprised of the Upper Columbia dams (Grand Coulee, Chief Joseph), Lower Columbia dams (McNary, John Day, The Dalles, Bonneville), and Lower Snake dams (Lower Granite, Little Goose, Lower Monumental, Ice Harbor). These resource groups will participate in the EIM as separate aggregated Participating Resources (APR). The amount of generation produced by these resources not bid into the EIM will be treated as an aggregated non-participating resource (ANPR) for purposes of the EIM. All other federal* *resources in the Bonneville balancing authority area will initially be non-participating resources in the EIM.*

Background and Context

Bonneville believes the EIM will provide Bonneville with new means to mitigate transmission congestion, as well as potential new opportunities to optimize the marketing of the FCRPS by monetizing its flexibility that would otherwise go unused. This optimization occurs within security constraints which seek to prevent the market's economic dispatch from causing congestion. The EIM develops price signals that reflect the extent to which those constraints are "binding" (*i.e.*, preventing an otherwise more economic dispatch). These price signals can help incentivize more efficient and reliable operation by reflecting operations and behaviors that implicate the security constraints.

These incentives, however, are limited to the extent market participants can effectively respond to the economic dispatch. As a general matter, the more accurately the EIM can model the resource responding to the congestion, the more certainty there is that the EIM will develop the most economic redispatch to relieve the congestion. The converse of this principle is also true. The less accurately the EIM can model the resource responding to congestion, the less confidence there is that the EIM will develop the most economic redispatch to relieve congestion. This distinction becomes important in the EIM when considering how Participating Resources are aggregated into a group.

The EIM permits a Participating Resource Scheduling Coordinator (PRSC) to aggregate its Participating Resources into one or more groups.[137] The benefit to grouping Participating Resources is that it distributes the market dispatch instruction over multiple resources. For instance, assume a PRSC bids a group of four resources into the EIM (Projects W, X, Y, Z), all of which have 25 MW of capability. If the EIM orders this group to *inc* by 40 MW, the EIM would distribute that order across all the projects based on a pre-defined distribution (referred to as a "generation distribution factor" or GDF). Assuming this group's GDF was .25, each Project in the group would be responsible for providing 25% of the 40 MW dispatch instruction, or 10 MW for each project (*e.g.,* W = 10 MW, X = 10 MW, Y = 10 MW, Z = 10 MW). Bonneville refers to this model as the aggregated participating resource or APR model.

[137] *See* EIM Business Practice Manual, CAISO, § 11.3.1, *available at* https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy Imbalance Market.

The EIM also includes additional functionality that allows the PRSC to choose which resources within the group respond to a market dispatch.[138] This functionality comes through overlapping participating and non-participating resources in a group. Bonneville refers to this model as the overlapping aggregated participating and aggregated non-participating resource model or APR/ANPR model. Returning to our example, a PRSC using the APR/ANPR model could choose the distribution of the market instruction among the four projects (*e.g.*, W = 20 MW, X = 10 MW, Y = 10 MW, Z = 0 MW).

Both operating models—the APR model and APR/ANPR model—allow Bonneville to control the hydraulic impact of EIM activity on the closely linked river operations in a similar fashion to how they are managed today. That flexibility, however, comes at the cost of not fully realizing the congestion relief and congestion revenue benefits that project level participation model would provide.

If Bonneville joins the EIM, Bonneville must decide how many APR groupings Bonneville intends to use to bid federal capability into the EIM. In addition, Bonneville must also determine whether it will use the APR/ANPR functionality to choose which generators within the aggregation will respond to market dispatches.

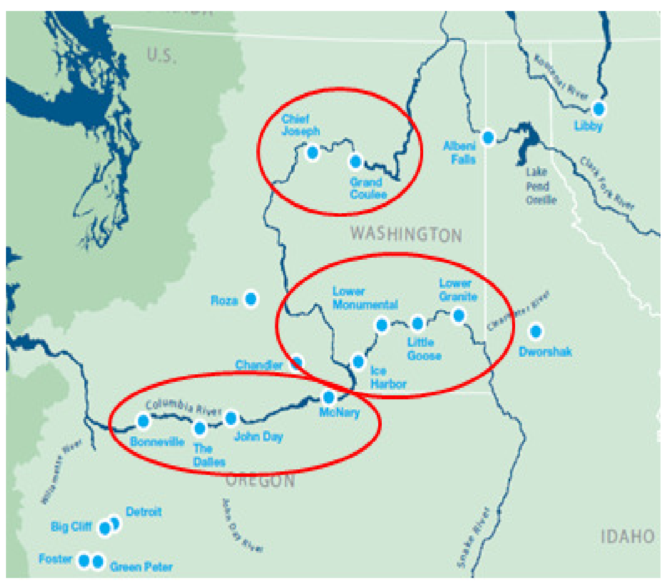
Aggregation of Federal Generation Proposal

Bonneville proposes aggregating the "Big-10" federal projects into three participating resource groups.

Upper Columbia:
- Grand Coulee (GCL)
- Chief Joseph (CHJ)

Lower Snake:
- Lower Granite (LWG)
- Little Goose (LGS)
- Lower Monumental (LMN)
- Ice Harbor (IHR)

Lower Columbia:
- McNary (MCN)
- John Day (JDA)
- The Dalles (TDA)
- Bonneville (BON)



[138] *Id.*

Bonneville is proposing to only aggregate the Big-10 projects into APRs because these are the federal projects that currently have the technical controls and hydraulic capabilities best suited to respond to EIM dispatches. The other 21 federal dams do not have the same controls or flexibility as these projects.

Bonneville is proposing the three participating resource aggregation model based on several factors. First, Bonneville considered the electrical similarities of the Big-10 projects. Bonneville conducted an electrical similarity analysis to determine how a change in generation at each project affects various transmission flowgates. The analysis looked at Bonneville's internal/network flowgates and established a set of Generation Shift Factors (GSFs) for each project, assuming all transmission lines were in service. Projects that had similar GSFs were considered to be electrically similar for that flowgate.[139]

Second, the three participating resource aggregation model also appropriately captures the unique hydraulic and operational aspects of the Big-10 projects. Storage projects operating in the upper part of the Columbia River system generally have different hydrologic and operating conditions and requirements than the projects located on the lower part of the Columbia River system, and the lower Snake River projects have their own unique requirements.

Bonneville considered other participation models, including less aggregation (making the Big-10 a single APR), and more (bidding in the available capability of each project from the Big-10). The following table shows the pros/cons of each model.

[139]In the analysis, if the difference between any two GSFs were less than 10%, the resources were considered to be electrically similar. Bonneville shared the results of its electrical similarity analysis with stakeholders at the October 11, 2018 public stakeholder meeting. *See* https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20181011-October-11-2018-EIM-Stakeholder-Mtg.pdf (slides 33-36).

Participation Alternative	Pros	Cons
One Aggregate	• Most similar to the current way of optimizing the FCRPS– less implementation requirements and costs to join the EIM	• Least efficient congestion relief and optimization of FCRPS • Lack of additional revenue associated with different Locational Marginal Prices (LMP)
Three Aggregates (Proposed)	• More efficient congestion relief than One Aggregate alternative • Moderate additional revenue opportunities associated with different LMPs	• May not fully realize congestion relief and revenue benefits that Project Level alternative would provide • Will require additional implementation requirements
Project Level	• Most efficient congestion relief • Most additional revenue opportunities associated with different LMPs	• More complexity, which increases the risk that BPA may, through its bids, operate the FCRPS less efficiently. • Will require additional implementation requirements

Bonneville is proposing to use the three participating resource aggregation model because it provides an appropriate balance between capturing the congestion benefits of the EIM while maintaining Bonneville's flexibility to respond and adjust to operational circumstances unique to each of the Big-10 projects. Bonneville views the three-aggregation proposal as a "starting point" for its initial participation in the EIM. Bonneville may modify its participation model, (*e.g.,* adding APRs, removing APRs) as Bonneville gains experience and confidence in the EIM. In addition, Bonneville's proposed aggregation must be reviewed by the CAISO before Bonneville joins the EIM.[140]

Overlapping Participating and Non-Participating Aggregation

Bonneville also proposes to use the APR/ANPR overlapping aggregation model. That is, each group of Participating Resources will have an amount of generation designated as participating in the EIM and another amount designated as non-participating. The benefit to Bonneville of this paradigm is that Bonneville can apply different "generation distribution factors"[141] to the participating and non-participating portions of the grouped

[140] *See* Market Operations Business Practice Manual v.60, CAISO, §3.1.2, *available at* https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Operations.

[141] In this context, a generation distribution factor is the percentage of an individual resource's share of the total aggregate for both the participating and non-participating portions of the aggregation. For example, for the Upper Columbia aggregation, Bonneville may designate Grand Coulee as .66 and Chief Joseph as .34 for

resources. This functionality is preferable because it allows Bonneville to choose which generators respond to a market dispatch. Bifurcating the aggregations in this manner is consistent with how Bonneville operates federal resources today.

Bonneville seeks comments on its proposals for aggregation and using the APR/ANPR model.

2. Transmission Usage – Interchange

Proposal: Bonneville is proposing to adopt the Interchange Rights Holder Methodology for making transmission available to the EIM.

Overview of EIM Transfers

As part of its decision to join the EIM, Bonneville must determine how it will make transmission available for EIM Transfers. EIM Transfers represent the net transfer of energy between EIM Entity balancing authority areas. The EIM uses transmission made available for EIM Transfers to develop the optimal dispatch of generation throughout the EIM footprint. Without transmission for EIM Transfers, the EIM can only optimize the load and generation within individual EIM Entities' balancing authority areas.

Energy delivered through EIM Transfers are not specifically tied to individual generators or loads, but are modeled as an *aggregate* delivery of power between EIM Entity balancing authority areas. Further, energy delivered to an EIM Entity's balancing authority area through an EIM Transfer may not ultimately serve load within that EIM Entity's balancing authority area. Instead, that energy may be used to facilitate further EIM Transfers to other EIM Entities. Transmission used to facilitate EIM Transfers is not reserved for any individual market participant's use. Rather, the EIM uses this transmission to develop the optimal wide-area dispatch. EIM Transfers only reflect the transfer of energy between EIM Entity balancing authority areas, not the transfer or transmission of energy within an EIM Entity's balancing authority area. EIM Transfers are limited to how much transmission capacity has been made available to the EIM to facilitate the transfer of energy among EIM Entities.

There are two existing methods of making transmission available for EIM Transfers:

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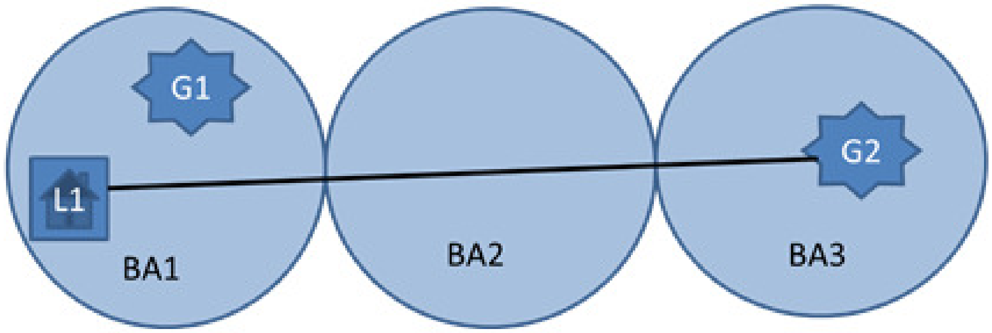
the participating portion of the aggregation, and Grand Coulee as .34 and Chief Joseph as .66 for the non-participating portion of the aggregation. The overlapping aggregation and non-aggregation paradigm will allow Bonneville to manage resource dispatch as it does today.

a. Direct Provision Methodology: The EIM Entity makes unscheduled transmission capacity between itself and other EIM Entities available for EIM Transfers. Such transmission capacity is non-firm and would be curtailed before all other transmission schedules at the North American Electric Reliability Corporation (NERC) curtailment priority level of 0-NX. To date, no EIM Entity is directly compensated for the transmission made available to the EIM in this way, although it may collect congestion revenue under certain circumstances.

b. Interchange Rights Holder Methodology: A transmission customer with long-term firm Point-to-Point transmission service between two EIM Entities (*i.e.*, an Interchange Rights Holder) may "donate" all or a portion of that long-term firm PTP transmission service to the EIM to facilitate EIM Transfers at the continuing discretion of the transmission rights holder. The transmission customer continues to pay the EIM Entity the applicable rate for long-term firm PTP transmission service, and the customer may collect congestion revenue under certain circumstances.

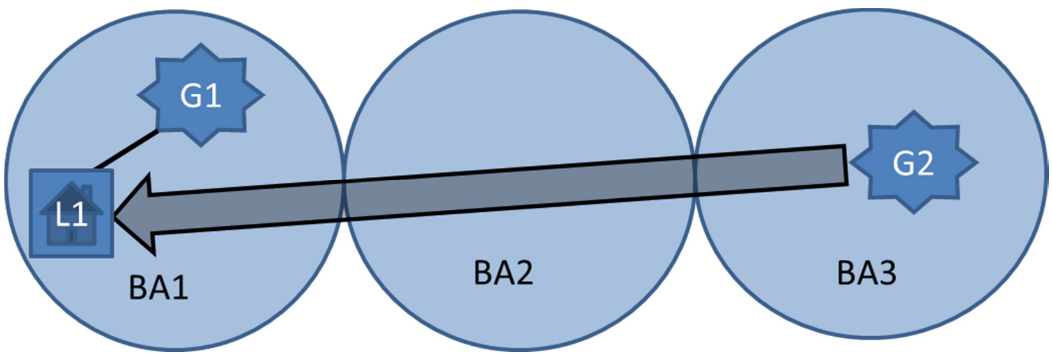
<u>*Bonneville's Proposal for EIM Transmission – Interchange Rights Holder Methodology*</u>

Bonneville is proposing to adopt the Interchange Rights Holder Methodology. Given the size and the position of the FCRTS, Bonneville expects to be a significant "net wheeler" in the EIM. In other words, Bonneville expects that a significant amount of EIM Transfers will originate in one EIM Entity's balancing authority area, be "wheeled" or transferred through the FCRTS, and ultimately serve load in another EIM Entity's balancing authority area. Under these circumstances, Bonneville believes the Interchange Rights Holder Methodology better balances the need to provide transmission to the EIM with collecting enough revenue to adequately and fairly recover the costs of the FCRTS. Under the Direct Provision Methodology, an EIM Entity does not receive compensation for the transmission it makes available to the market. On the other hand, the Interchange Rights Holder Methodology ensures that Bonneville is compensated for the transmission service provided to the EIM. This methodology gives an interchange rights holder the ability to choose how to best use their transmission service. See the figures below for a demonstration of net-wheeling.



Example 1: Absent the EIM – Currently, Transmission Is Purchased Across Each Balancing Authority Area

Load L1 purchases and schedules transmission across BA1, BA2, and BA3 in order to access the cheaper generation G2. G1, a high cost generator, is dispatched to supply balancing in BA1.



Example 2: With the Direct Provision Methodology – Unrecovered Costs

Load L1 purchases transmission in BA1, and schedules from generator G1, a high cost generator thus satisfying its resource sufficiency requirement. However, in operations, the EIM dispatches the cheaper generation G2 to serve L1, using uncompensated transmission across BA2.

The Interchange Rights Holder Methodology is consistent FERC precedent

The Interchange Rights Holder methodology is established and tested in the EIM. In fact, the first EIM Transfers were made available in this manner on the Northwest AC Intertie for transfers between PACW and the CAISO. This method has been developed and established when there are multiple transmission owners and operators of transmission paths. FERC has accepted Tariff provisions from multiple EIM Entities for the provision of EIM Transfer transmission via the Interchange Rights Holder methodology.[142] Further, since it has been in wide use throughout the Pacific Northwest over the last few years, it has been proven to provide sufficient transmission for the proper functioning of the EIM as it is designed today.[143] As the EIM and other markets evolve in the West, Bonneville will evaluate if any changes need to be made to this policy.

Bonneville seeks comment on its proposal to adopt the Interchange Rights Holder Methodology.

3. System Operations Tools

Proposal: Bonneville proposes to maintain its current suite of operational tools used to manage the federal power and transmission systems if it becomes an EIM Entity.

Background

This section focuses on the operational tools currently used by Bonneville to meet its reliability and environmental responsibilities, and whether Bonneville can continue to use these tools if it joins the EIM. In short, Bonneville believes that it can continue using these tools if it joins the EIM.

Before addressing specific tools below, it is important to note two general principles. First, in regard to applicable NERC reliability standards, Bonneville will continue to be solely responsible for complying with those standards in its balancing authority area and for the transmission system it owns or operates even if it joins the EIM. The CAISO assumes no responsibility regarding reliability standards applicable to EIM Entities.

Second, Bonneville will also remain responsible for meeting its environmental responsibilities if it joins the EIM. While the CAISO, as the EIM market operator, will respect Bonneville's environmental responsibilities, the CAISO will not be responsible for complying with those obligations.

Finally, it is worth noting that Bonneville employs many operational systems, tools, and processes to reliably operate the federal power and transmission systems in order to meet its Tariff, compliance, and environmental requirements. Bonneville believes these

[142] *See, e.g., PacifiCorp*, 147 FERC ¶ 61,227, at P 113 (2014); *PacifiCorp*, 149 FERC ¶ 61,057, at P 32 (2014); *Puget Sound Energy*, 155 FERC ¶ 61,111, at PP 11, 73, 76 (2016).
[143] *Id.*

operational systems, tools, and processes are compatible with the EIM and will continue their use if it joins the EIM.

Bonneville has received specific inquiries about two of its operational tools—Operational Controls for Balancing Reserves (OCBR) and Oversupply Management Protocol (OMP)—regarding how they would be impacted if Bonneville were to become an EIM Entity. The following two subsections specifically address those tools. Based on Bonneville's analysis and discussions with the CAISO to date, Bonneville can become an EIM Entity and maintain both of these tools.

Operational Controls for Balancing Reserves (OCBR)

OCBR is a system reliability tool that Bonneville uses to balance load and generation in its balancing authority area.[144] Generally, actual generation and load should match scheduled generation and load for the hour. Bonneville uses OCBR when within-hour variability of generation and load consumes balancing reserve capacity to a certain level. Under OCBR, Bonneville will take steps to reduce variability, such as curtailing generation schedules to actual generation levels or limiting generation to schedule, in order to maintain Bonneville's system reliability.

While the EIM will optimally dispatch imbalance energy every 5 minutes to Bonneville's balancing authority area, Bonneville believes that it is important to maintain OCBR. Bonneville is still required to hold and deploy regulation to balance generation and loads in its balancing authority area within the CAISO's 5-minute EIM dispatches, for which OCBR will be necessary to manage regulation over-deployment. OCBR is also necessary to maintain in case Bonneville is unable to participate in the market (*e.g.*, withdraws or fails resource sufficiency for a given interval).

Oversupply Management Protocol (OMP)

OMP is an operational tool used to address certain environmental conditions in the Columbia River Basin and maintain load-generation balance in Bonneville's balancing authority area during those conditions. During times of river flows, typically in the spring when loads in Bonneville's balancing authority area 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,

[144] Bonneville uses certain hydro projects in the FCRPS to respond to within-hour deviations in generation and load by constantly increasing and decreasing generation output. This balancing is necessary to keep the electric system stable.

at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas (TDG) and is regulated by the states of Oregon and Washington under the Clean Water Act.

When the Columbia River reaches TDG limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville offers this electricity as low as zero cost; however, 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 Transmission Tariff, creating a least-cost cost curve for displacing generation in the balancing authority area and reimbursing displaced generators for certain costs related to the displacement, so that Bonneville can pass water through its generating turbines and maintain generation-load balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.[145]

At this time, Bonneville is proposing to maintain OMP as it is currently set forth in Attachment P. If Bonneville joins the EIM, it still needs a mechanism to reduce generation located in its balancing authority area to minimum generation levels in order to comply with its environmental responsibilities. Bonneville does not believe that the EIM provides a market solution that achieves that objective as effectively as OMP today. That said, Bonneville will consider other methods of managing over-generation in its balancing authority area if more effective ways of achieving the goals of OMP are discovered. OMP is also necessary to maintain in case Bonneville is unable to participate in the market (*e.g.*, withdraws or fails resource sufficiency for a given interval).

Conclusion

Joining the EIM does not change Bonneville's system reliability and environmental responsibilities that necessitate the system operations tools discussed above. As such, Bonneville proposes to maintain these tools to manage the federal power and transmission systems if it becomes an EIM Entity. Bonneville solicits comments from stakeholders on this proposal.

4. Carbon Obligations and Related Matters

Proposal: Bonneville's policy proposal on carbon in the EIM is to opt out of selling directly into California via the EIM unless Congress grants Bonneville authority to directly purchase

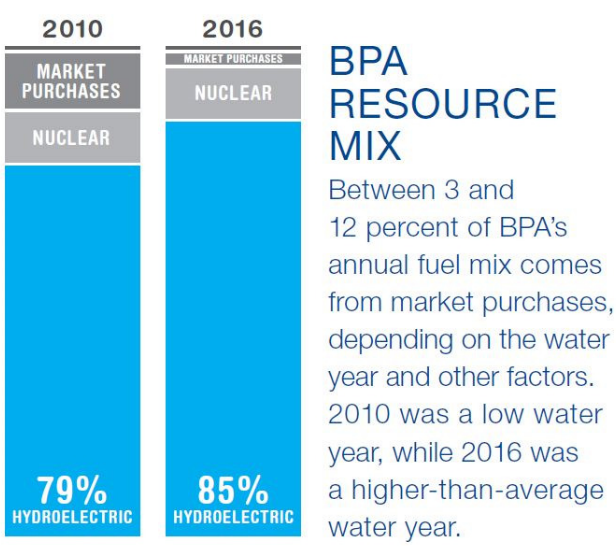
[145] *Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 149 FERC ¶ 61,044 (2014).

allowances under California and other state carbon programs. Bonneville does not believe this issue precludes its participation in the EIM.

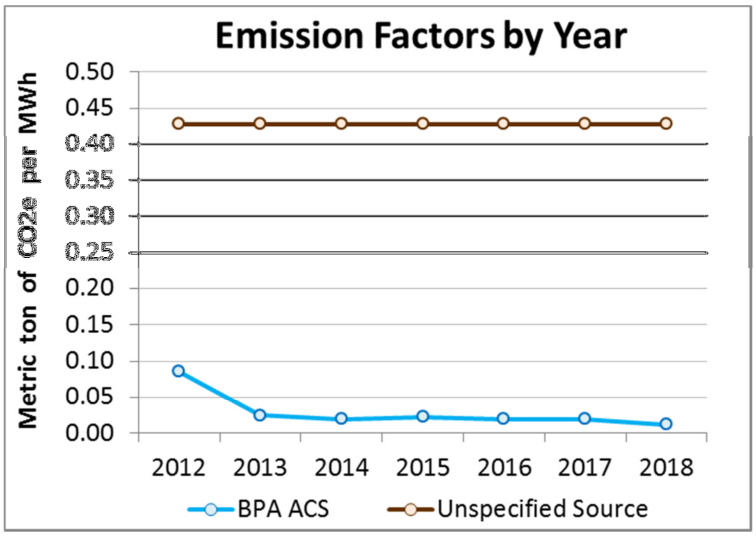
<u>Background on Carbon in the EIM</u>

In accordance with California's cap-and-trade program administered by the California Air Resources Board (CARB), any entity that exports electricity into California (from another state) must purchase carbon allowances to cover carbon emissions associated with the electricity imported into California. If other states adopt cap-and-trade or other carbon pricing programs, electricity that is imported into those states could be similarly regulated.

While the hydro system and Columbia Generating Station produce carbon-free electricity, there is a small amount of carbon associated with the FCRPS. Bonneville uses federal power produced by FCRPS and other resources (non-federal) it acquires to meet its contractual supply obligations. In meeting those obligations Bonneville regularly acquires power from the market to balance its resources and loads. Market purchases typically account for between 3 to 12 percent of Bonneville's total annual power supply. States with greenhouse gas (GHG) reporting programs such as California typically attribute a default emissions factor to market purchases. Thus, because of the emissions attributed to the market purchases, the FCRPS as a whole has a small amount of carbon emissions associated with it.



Since the implementation of the California-cap-and-trade program in 2013, Bonneville has been recognized by the CARB as an Asset Controlling Supplier (ACS). An ACS is a specific type of electric power entity approved and registered by CARB. CARB assigns a system emission factor for the wholesale electricity procured from the ACS's system and imported into California. Bonneville and two other entities (Tacoma Power and Powerex) have been approved by CARB as ACSs. Bonneville voluntarily reports its fuel mix data to CARB and, based on that reporting, CARB assigns Bonneville an ACS emissions factor. Bonneville's ACS emission factor has been very low over the last few years, averaging around 0.02 metric tons of CO_2 equivalent per MWh. This constitutes a need to purchase roughly one allowance for every 50 MWh sold into California, and the cost of compliance is roughly $0.30 per MWh at prevailing carbon allowance prices.



Units:	Metric ton CO2e per MWh	MWh	$ per metric ton CO2e	$ per MWh
Source	**Emission Factor**	**Imported Power**	**GHG Allowance Price**	**GHG Cost**
Unspecified Source	0.43	1	$16	$6.8
BPA ACS	0.02	1	$16	$0.3
Difference	0.41			$6.5

This low ACS emission factor adds value to FCRPS sales into the California market. However, the federal government has determined that California carbon allowances constitute a state tax. Under the U.S. Constitution a state cannot tax the federal government, in particular a federal agency like Bonneville, unless Congress specifically authorizes the agency to pay the tax. As a consequence, Bonneville currently cannot purchase these allowances. In order to sell into California without purchasing carbon allowances, Bonneville has entered into third-party arrangements to sell to entities that, in turn, take Bonneville's power into the California market and incur the resulting carbon compliance obligation. These third-party arrangements are inefficient and have an incremental cost. In the near future, Bonneville's inability to purchase carbon allowances could impact Bonneville's marketing in other western states if other states adopt cap-and-trade programs similar to California's.

As it pertains specifically to the EIM, CARB considers the Participating Resource Scheduling Coordinator to be the entity with the compliance obligation under the cap-and-trade program, meaning the Participating Resource Scheduling Coordinator is responsible for acquiring the allowances to cover any carbon associated with the EIM import. Entities participating in the EIM must indicate a GHG adder cost in their bid that reflects the cost of purchasing any allowances associated with the import. However, there is an option that Participating Resource Scheduling Coordinator can choose to avoid deliveries to California and thus avoid the GHG adder cost.

Bonneville is proposing to use three aggregations of the big-10[146] hydro projects for bidding resources into the EIM, but the ACS emissions factor would still be attributed to Bonneville's bids. This is because of the system sales concept, discussed in section III.b.3, and because Bonneville can only bid from these aggregated projects if it operates its entire system in a way that "sets up" those big-10 resources to be able to bid. That is, with a run of river system water must be moved and stored in a coordinated fashion in order for the aggregated resources to be available.

Intended Resolution

Bonneville would need statutory expenditure authorization in order to directly purchase allowances under California's, and potentially other states', cap-and-trade programs. This authorization is important to Bonneville in order to be able to sell into evolving markets such as the EIM. The authorization would provide cost savings because Bonneville would not have to go through third-parties (and pay them) to access the California wholesale market. Additionally, the authorization is important because there is no guarantee that third parties will always be willing to provide this service to Bonneville. Finally, other

[146] *See* section III.e.1.

states may also enact carbon pricing programs that place a compliance obligation on electricity, similar to California's program.

As indicated above, EIM participants can elect to not sell into California. In the event Congress does not authorize Bonneville to purchase allowances in time for participation in the EIM, Bonneville intends to opt out of selling directly into California via the EIM. In that case, no power would be deemed sold into California and Bonneville would not incur any compliance obligations under the California cap-and-trade program because Bonneville would not be importing into California through the EIM. Bonneville recognizes that this could impact the value of participating in the EIM; however, the expectation is that this impact would be small.[147] If Congress authorizes Bonneville to purchase allowances at a later date, Bonneville can change its election and begin selling into California via the EIM at that time.[148]

Bonneville also identified another potential option for participation in the EIM, using a third party as the Participating Resource Scheduling Coordinator. Since CARB identifies the Participating Resource Scheduling Coordinator as the entity with the compliance obligation under the cap-and-trade program, if Bonneville utilized a third party, that party would take on the compliance obligation. In CARB's interpretation, the Scheduling Coordinator would be the "electricity importer" into California, thus they would be required to obtain carbon allowances and surrender them to CARB. This third party would theoretically be performing various tasks for Bonneville, which is important in ensuring Bonneville is getting additional value from the third party and this is not simply a direct pass-through to cover the costs of the carbon allowances. However, other than identifying this as a potential option, Bonneville has not explored whether it is feasible to use a third party as the Participating Resource Scheduling Coordinator, and what business value the third party might provide aside from eliminating Bonneville's CARB compliance obligation.

Conclusion

Bonneville's policy proposal on carbon in the EIM is to opt out of selling directly into California via the EIM unless Congress provides authorization for Bonneville to directly purchase allowances under California and other state carbon programs. Bonneville does not believe this issue precludes its participation in the EIM.

Bonneville welcomes comments on this policy proposal.

[147] *See* section III.d.2.ii.
[148] The fiscal year 2020 House Energy and Water Development Appropriations bill, which passed out of the full House Appropriations Committee on May 21, 2019, includes statutory language which would give Bonneville expenditure authorization to purchase these carbon allowances if enacted.

5. Market Power (LMPM and DEB)

<u>Proposal</u>: Bonneville proposes that the enhancements to the CAISO's Local Market Power Mitigation procedures to be filed this summer with FERC for approval are sufficient to address Bonneville's concerns regarding the current procedures. Bonneville will continue to monitor the progress of the enhancements through FERC's approval process and, if approved, the CAISO's implementation process. If the proposed enhancements are not approved or are substantially revised by FERC such that Bonneville's concerns are no longer addressed, Bonneville will reconsider whether (or how) it will join the EIM.

<u>Background</u>

One of the primary objectives of electricity market design is efficient load service; that is, the deployment of lowest cost generation resources to serve loads recognizing transmission constraints. Achieving this efficiency requires a market design that prevents participants from exercising market power by raising market prices above otherwise competitive market outcomes.

The CAISO administers the Local Market Power Mitigation (LMPM) procedures set forth in the CAISO's Tariff to determine when and how to mitigate the impacts of a participant potentially exercising market power. The CAISO applies the LMPM procedures to the entire EIM footprint. Thus, if Bonneville joins the EIM, the CAISO's LMPM procedures will apply to EIM dispatches into and out of Bonneville's balancing authority area. As discussed further below, Bonneville has serious concerns with the CAISO's current LMPM procedures and their impact on Bonneville's potential EIM participation with its hydro resources.

Today, if an EIM participant is determined to have market power, the CAISO may mitigate the participant's bid(s) to a Default Energy Bid (DEB), which is used in the CAISO's optimization (or market run). Presently, market participants may choose from three options in determining their DEB:

1. *Variable Cost Option*:[149] Based on heat rate, fuel price, GHG costs, etc.;
2. *Locational Marginal Price (LMP) Option*:[150] Based on lowest 25th percentile of LMPs at which a Participating Resource was dispatched in the last 90 days; or
3. *Negotiated Rate Option*:[151] Based on a formula bilaterally negotiated between a Participating Resource Scheduling Coordinator and the CAISO/DMM.

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[149] CAISO Tariff § 39.7.1.1.
[150] *Id.* at § 39.7.1.2.
[151] *Id.* at § 39.7.1.3.

Bonneville's Concerns Regarding the CAISO's Current LMPM Procedures

Bonneville has several concerns regarding the CAISO's current LMPM procedures. First, the procedures do not adequately address energy limited hydro systems, such as the FCRPS.[152] While existing options may be sufficient to approximate the marginal cost of supply for most thermal-based resources in the EIM footprint, the existing options do not capture the forward-looking nature of the opportunity cost of hydro generation.[153]

Bonneville also believes that the duration of a DEB under the current procedures is unnecessary. Currently, if a participant is determined to have market power, it would be mitigated throughout the remainder of the operating hour, instead of the just the specific 15-minute interval(s) in which the participant is determined to have market power.

Finally, Bonneville is concerned that the application of existing DEBs has been known to induce unintended flows between EIM Entity balancing authority areas or result in incremental transfers beyond the transfers modeled in unmitigated market runs. This has the potential to discourage additional EIM participation.

The CAISO's Proposed Modifications to its LMPM Procedures

The CAISO initiated an LMPM stakeholder initiative in September 2018 addressing the issues discussed above.[154] Bonneville and other Pacific Northwest parties with hydro resources actively participated in that initiative to persuade the CAISO to develop a default energy bid formulation for hydro resources with storage capability and to enhance other components of the LMPM procedures.

Bonneville views the outcome of the LMPM stakeholder initiative as favorable to Bonneville and other Pacific Northwest hydro generation parties. Enhancements to the LMPM procedures included:

[152] An "energy limited hydro system" is one in which the binding constraint is fuel (water) rather than a limit derived by machine-rated (nameplate) capacity.
[153] Opportunity costs for hydro resources should include the costs of forgone future generation when prices are higher due to market dispatches in the present or near-term.
[154] For more information regarding the CAISO's 2018 LMPM Enhancements stakeholder initiative, see http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2018.aspx.

1. A fourth DEB option that more accurately reflects the opportunity costs of hydro resources. The fourth DEB option includes:
    a. A formula that incorporates the forward storage horizon of a Participating Resource;
    b. A multiplier that recognizes the inherent variation of prices and a Participating Resources' ability to target or shape its output to the highest value periods;
    c. Inclusion of a price floor based on a gas turbine heat rate meant to proxy a replacement power purchase;
    d. Recognition of the combined value of energy and firm transmission rights when coupled together for delivery; and
    e. The ability to update parameters of the DEB, such as multiplier levels, upon request.
2. Market power mitigation will occur for only the 15-minute interval(s) when market power is determined to exist instead of the entire operating hour.
3. Market rules will limit transfers between two EIM balancing authority areas to a specified amount so that unintended market flows due to mitigation are minimized.

This summer the CAISO plans to file the proposed Tariff language reflecting these enhancements with FERC for approval. Bonneville will intervene in and closely follow that proceeding.

Conclusion

Bonneville is satisfied with the outcome of the CAISO's LMPM stakeholder initiative and the substance of the LMPM enhancements to the CAISO's Tariff to be filed with FERC this summer. The issues raised by Bonneville and other Pacific Northwest parties with hydro resources were largely addressed in a satisfactory manner during the CAISO's stakeholder initiative process. That said, Bonneville will closely monitor the CAISO's Tariff filing proceeding before FERC. Assuming FERC approves the current draft language, Bonneville will consider the proposed enhancements sufficient to address its current concerns with the CAISO's current LMPM procedures. If FERC does not approve the CAISO's proposed Tariff language or significantly modifies it, Bonneville will revisit the LMPM issue and determine whether it will pursue joining the EIM using the negotiated DEB option. Please provide comments on Bonneville's proposed approach to the LMPM issue.

6. Load Aggregation

Proposal: Bonneville proposes to initially have one load aggregation point (LAP) if it becomes an EIM Entity.

A load aggregation point (LAP) is a weighted average of multiple locational marginal price nodes used for the settlement of non-participating load imbalance[155] in an EIM Entity's balancing authority area.

Bonneville staff has discussed load modeling with the CAISO and has benchmarked other EIM Entities regarding how they model their loads. To date, every EIM Entity has chosen to use a single LAP for their respective balancing authority areas.[156] The consensus is that having a single LAP reduces workload, costs, and complexity because having multiple LAPs requires different load forecasts, prices, meters, and uninstructed imbalance energy settlements[157] for each LAP. The reason to have multiple LAPs would be if there is significant weather variation across a balancing authority area resulting in dramatically different demand forecast patterns, or significant and persistent congestion across subsystem boundaries resulting in significantly different prices for multiple LAPs. Such conditions do not exist in Bonneville's balancing authority area, so Bonneville does not see a reason to use more than one LAP.

A single LAP for Bonneville's entire balancing authority area would be easier to manage from both an operational and settlements perspective and have less initial startup costs than designing systems to accommodate multiple LAPs. This, however, does not preclude Bonneville from deciding later to pursue a multiple LAP model as it gains more experience in the EIM.

Conclusion

At this time, Bonneville has not identified a compelling operational or business reason to use more than one LAP. If Bonneville decides at a later date to pursue additional LAPs, it will do so. Bonneville solicits stakeholder input and comment on this proposal.

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[155] Non-participating load is load that does not have an economic bid in the EIM.
[156] PacifiCorp has separate LAPs for its PAC-East and PAC-West balancing authority areas.
[157] Uninstructed energy imbalance is comparable in principle to Bonneville's Energy Imbalance service today.

7. Resource Sufficiency – Balancing Authority Area Level

Proposal: *Bonneville proposes that the CAISO's resource sufficiency requirements are not an impediment to Bonneville participating in the EIM.*

Background

The CAISO uses a resource sufficiency (RS) evaluation to determine whether each EIM Entity has procured, prior to each operating hour, sufficient energy, capacity, flexibility, and transmission to serve imbalance in its own balancing authority area.[158] The objective of the RS evaluation is to ensure that an EIM Entity does not lean on other EIM Entities in real-time to serve imbalance in its balancing authority area.

The CAISO's real-time RS evaluation for the EIM is not a longer-term resource adequacy program as applied to the CAISO's other markets. The CAISO does not enforce any resource adequacy requirements as part of its RS evaluation, and there are no resource adequacy standards applicable to the EIM. There are no capacity payments or must-offer obligations associated with RS. Moreover, outcomes of the RS tests are not determinative as to whether an EIM Entity is meeting applicable NERC reliability standards. An EIM Entity could fail RS and still meet applicable NERC reliability standards.

As shown in the table below, the CAISO evaluates each EIM Entity for RS every hour in real-time using four tests, which are performed sequentially. The RS evaluation determines if an EIM Entity is allowed to participate in the EIM to optimally serve its imbalance needs. If an EIM Entity fails RS, it must rely on its own resources, including any bilateral arrangements with external resources and limited interaction with the EIM to meet its imbalance. Capacity held for balancing authority operational requirements is not considered as part of the capacity needed to meet RS requirements.

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[158] For a more in-depth discussion of the CAISO's RS evaluation and process, see Bonneville's stakeholder materials dated January 16, 2019, which can be viewed at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190119-EIM%20Stakeholder%20Mtg.pdf.

RS TEST	DESCRIPTION	CONSEQUENCES OF FAILURE
Transmission Feasibility Test	Identifies if an EIM Entity's base schedules are limited by congestion	None— advisory only.
Balancing Test	Ensures that an EIM Entity's load/ resources are balanced going into the hour	Failure does not result in limitations on EIM transfers but will be used to determine if an EIM Entity is evaluated for over/under scheduling penalties.
Bid Range Capacity Test	Ensures that the EIM Entity has bid range to cover expected imbalance	An EIM Entity can fail in one or both directions (import and export) for a 15-minute market interval. Failure of capacity test in a given direction results in failure of the Flexible Ramp Sufficiency test in the same direction.
Flexible Ramp Sufficiency Test	Ensures the EIM Entity has ramping capability to meet expected load ramp and uncertainty	An EIM Entity can fail in one or both directions (import and export) for a 15-minute market interval. Failure results in EIM transfers being limited in the failed direction for that interval.

Impacts of the CAISO's RS Evaluation on Bonneville

While Bonneville has not determined how it will bid flexibility in an EIM, Bonneville's preliminary analysis indicates that it would pass the RS evaluation a significant amount of the time using historical spinning availability. This provides Bonneville with a high level of confidence that it can achieve the benefits described in the business case. The likelihood of passing the RS evaluation would increase if any additional bid flexibility is made available, whether from federal or non-federal Participating Resources.

Conclusion

The CAISO's resource sufficiency standards are not an impediment to Bonneville participating in the EIM. Bonneville seeks comments on this proposal.

IV. EIM Implementation Agreement

Proposal: Bonneville proposes to execute the EIM Implementation Agreement included as Attachment C. Bonneville's Implementation Agreement includes a high-level project schedule and funding commitment by Bonneville of $1.87 million to pay the CAISO for funding the costs associated with joining the EIM.

a. Background

An EIM Implementation Agreement is the first in a series of agreements necessary for a balancing authority to become an EIM Entity.[159] In general terms, an Implementation Agreement establishes a high-level project plan and schedule that sets forth the steps that a balancing authority and the CAISO must take in order for a balancing authority to join the EIM. However, the Implementation Agreement does not obligate a balancing authority to join the EIM.

The Implementation Agreement also requires a prospective EIM Entity to fund a portion of the CAISO's already incurred EIM-related startup costs. To ensure the fair and equitable allocation of such costs, the funding amount set forth in each Implementation Agreement is based on a formula that considers the percentage of a prospective EIM Entity's total balancing authority net energy for load (NEL)[160] as part of the total NEL in the entire WECC footprint. The CAISO then uses this percentage to allocate its total estimated start-up costs for the EIM to each prospective EIM Entity in the Implementation Agreement.[161] The CAISO's total estimated startup costs for the EIM include:

[159] Following an EIM Implementation Agreement, the CAISO and prospective EIM Entity must execute an EIM Entity Agreement, EIM Scheduling Coordinator Agreement (if the Entity is serving as its own Scheduling Coordinator), meter agreement, and other potential agreements as necessary. For more information regarding the agreements that are necessary in the EIM, please see https://www.westerneim.com/Documents/EIMTrack2Overview-Agreements.pdf.

[160] NERC defines NEL as "net generation of an electric system plus energy received from others less energy delivered to others through interchange. It includes system losses but excludes energy required for the storage of energy at energy storage facilities." NERC Rules of Procedure, Definitions, Appendix 2, *available at* https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20180719.pdf.

[161] The CAISO files each executed Implementation Agreement with the Federal Energy Regulatory Commission (Commission) for approval. The filing of the Implementation Agreement includes a declaration from a CAISO representative that outlines the basis for and allocation of the CAISO's estimated EIM startup costs to EIM Entities in the agreement. The Commission has found the CAISO's cost-allocation mechanism to be just and reasonable and approved it accordingly. *See, e.g., Cal. Indep. Sys. Operator*, 143 FERC ¶ 61,298, at PP 4-5 (2013) (the Commission's acceptance of the CAISO's cost allocation of EIM startup costs in PacifiCorp's Implementation Agreement).

CAISO Estimated EIM Start-Up Costs (in thousands of dollars)	
Licenses	12,150
EMS system improvements	1,000
Data storage	2,000
Necessary hardware upgrades	500
Production software modifications	1,000
Network configuration and mapping	500
Integration	500
Testing	1,500
System performance tuning	250
Training and operations readiness	150
Project management	150
Total	**19,650**

The Implementation Agreement terminates on its own terms when an EIM Entity "goes live" in the EIM, meaning when market transactions become financially binding. Subsequent agreements such as the EIM Entity Agreement and EIM Entity Scheduling Coordinator Agreement, which are signed before an EIM Entity's go live date, continue in effect so long as a balancing authority is participating in the EIM. A prospective EIM Entity can terminate the EIM Implementation Agreement on 30 days' written notice and is only responsible for paying the costs associated with milestones accomplished at the time written notice is provided. In addition, the CAISO will work with a prospective EIM Entity to extend the Agreement if additional time is necessary for implementation.

b. Bonneville's Implementation Agreement with the CAISO

Bonneville's proposed Implementation Agreement is included in Exhibit C. It is generally similar in substance and form to all other Implementation Agreements that have been negotiated and executed by the CAISO and other existing or prospective EIM Entities. That said, Bonneville's Implementation Agreement does have some unique provisions, which are addressed in more detail below.

Bonneville's funding requirement set forth in the Implementation Agreement is $1.87 million. As discussed in the preceding section, this represents Bonneville's proportional share of the CAISO's total estimated start-up costs for the EIM based on

Bonneville's NEL within the WECC footprint.[162] As set forth in section 4(c) and Exhibit A of the Implementation Agreement, Bonneville will make six equal payments to the CAISO tied to particular project milestones.

Bonneville's Implementation Agreement also includes language regarding FERC's lack of jurisdiction over Bonneville in section 1(e) that is comparable to the language used by other non-jurisdictional entities in their Implementation Agreements.

c. Bonneville-Specific Language in the Implementation Agreement

Section 14 of Bonneville's Implementation Agreement contains several provisions specific to Bonneville's implementation efforts and its potential participation in the EIM. The provisions described below that are applicable to Bonneville's potential participation in the EIM will be memorialized in subsequent participation agreements, such as the EIM Entity Agreement.

1. *Statutory, Regulatory, and Contractual Requirements*. This provision provides that Bonneville's EIM implementation and participation will be consistent with its statutory, regulatory, and contractual requirements. For more information regarding these requirements, please see section III.b.

2. *Voluntary Market Participation*. This provision provides that Bonneville's EIM participation will be predicated on rules voluntarily allowing market entry and exit, voluntarily submitting bid and offer volumes and pricing, voluntarily donating transmission for EIM Transfers, and voluntarily foregoing EIM Transfers in one or more specified operating intervals consistent with the CAISO and Bonneville Tariffs. As described in several other sections of this Proposal, the voluntary nature of EIM participation will be a key consideration of Bonneville's ultimate decision regarding whether to join the EIM.

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[162] Bonneville's $1.87 million payment was calculated as follows:

1. To determine a per MWh charge for creating and implementing the EIM outside of the CAISO's balancing authority area assessed to all prospective EIM Entities, the CAISO's estimated EIM startup cost of $19,650,000 million was divided by the total WECC-wide NEL, excluding the CAISO's NEL, of 636,200,000 MWh which equals $.031 per MWh. The CAISO's EIM startup costs are set forth above.
2. To determine Bonneville's share of the CAISO's startup costs, Bonneville's NEL of 60,000,069 MWh was then multiplied by the .031 MWh, which equals $1,869,302 (or rounded to $1.87 million).

The NERC data used for these calculations can be accessed at: https://www.nerc.com/gov/bot/FINANCE/2018%20NERC%20Business%20Plan%20and%20Budget%20%20Final/2018%20Assessments_2016%20NEL_FINAL_8.18.17.pdf.

3. *Reliability and Operation of the Federal Power and Transmission Systems*. This provision provides that Bonneville retains authority over matters relating to reliability and operation of the FCRPS and FCRTS. As described in section III.e.3, Bonneville will retain its existing reliability tools.

4. *Federal Generation Participation*. This provision allows Bonneville to utilize the CAISO's resource aggregation models for EIM participation. As discussed in section III.e.1, Bonneville is proposing to join the EIM using three aggregated Participating Resources.

5. *Automation Support*. This provision states that the CAISO will provide technical support as Bonneville works to automate many of the interactions with existing EIM interfaces during the implementation phase. Bonneville has identified the following interactions for potential automation: declaring contingency events, manual dispatches, load biasing, and setting EIM transmission interface operating limits. Bonneville continues to scope what interactions it will seek to automate.

6. *Greenhouse Gas Attributes.* This provision provides that if Bonneville allows FCRPS energy to be delivered directly to California in the EIM, those deliveries will be consistent with California's Cap and Trade program and may include Bonneville's status as an Asset Controlling Supplier. For more information regarding Bonneville and California's carbon policy, see section III.e.4.

7. *Base Schedule Submission Timeframes*. This section provides that the CAISO will pursue changing the market closing timeline for financially binding hourly resource plans from T-40 to T-30. Bonneville believes this change will provide benefits to its stakeholders, particularly customers holding Slice power sales contracts.

8. *Consideration of Other EIM Enhancements*. This section includes four potential enhancements that Bonneville will propose in the CAISO policy-making process. While Bonneville's participation is not expressly contingent upon these enhancements, Bonneville believes these are important enhancements to the EIM that should be considered by the CAISO. The CAISO will explore these enhancements with Bonneville and other interested stakeholders. These enhancements include:

a. *Improving the accuracy of hourly resource plans*. This proposal will focus on certain market design enhancements that would improve the accuracy of hourly resource plans and, in turn, help EIM Entities meet their respective resource sufficiency obligations.

b. *Permit resource sufficiency obligation transfers, e.g., bid range transfers*. This proposal will allow an EIM Entity to bilaterally negotiate a transfer of capacity to another EIM Entity to help the latter Entity meet its resource sufficiency obligations.

c. *Improve the flexible ramping sufficiency test*. This proposal will focus on enhancements improving the flexible ramping sufficiency test, such as the incorporation of VER forecasts into the flexible ramping requirement computation.

d. Increase transparency of data required for validation of EIM settlement statements. This proposal will explore appropriate methods for the CAISO to share additional market data with EIM Entities to allow them to fully validate the EIM settlement statements they receive from the CAISO.

Bonneville requests stakeholder comments and feedback on the Implementation Agreement included as Attachment C.

V. Remaining Policy Decisions Planned for Phase III

As explained in section II, Bonneville will hold stakeholder meetings, as well as pre-rate and pre-Tariff proceeding workshops on the remaining important policy issues that are not being covered in this Proposal and the ROD. These issues include:

a. Transmission Usage – Network
b. Allocation of EIM Charge Codes
c. Resource Sufficiency – Sub-Balancing Authority Area Level
d. Transmission Losses
e. Non-federal Resource Participation Requirements
f. Settlements/Billing (Mechanics)
g. Data Submission Requirements
h. Metering Requirements

This section briefly describes the policy issues that Bonneville plans to address during Phase III.

a. Transmission Usage Network

As discussed in section III.e.2, Bonneville is proposing to utilize the Interchange Rights Holder methodology to make transmission available for EIM Transfers—transfers between EIM balancing authority areas. That decision does not address what, if any, provisions are necessary regarding transmission internal to Bonneville's own EIM balancing authority area.

Bonneville plans to address the subject of transmission within the EIM balancing authority area during Phase III. That process may include provisions for Participating Resources and for loads. Bonneville will likely have a similar high-level rubric for this subject as it did for EIM Transfers—striking a balance between the efficient operation of the market with ensuring cost recovery. Bonneville will also discuss with stakeholders the mechanics of managing internal transmission consistent with EIM operations.

b. Allocation of EIM Charge Codes

If Bonneville joins the EIM as an EIM Entity, Bonneville will be responsible for receiving, verifying, and paying bills, comprised of multiple charge codes, generated by the CAISO settlement system. A charge code refers to a specific settlement calculation identified in the CAISO's Business Practice Manual.[163] There are around 44 active charge codes that the CAISO could settle with Bonneville in the EIM.[164]

CAISO settlement invoices are aggregated at the balancing authority area level, and not broken down by individual Bonneville customer. Nonetheless, Bonneville must pay the CAISO, and then use its own rates to recover these costs from its Tariff customers. As such, Bonneville will need to decide whether and how it will allocate the CAISO's settlement charge codes to its transmission customers. Note that Participating Resources are billed by and settle charges directly with the CAISO.

The Phase III process is expected to result in a cost allocation design which will be included in the BP-22 and TC-22 proceedings, as appropriate.

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[163] *See* CAISO Tariff, Appendix A, *available at* http://www.caiso.com/Documents/AppendixA-MasterDefinitionSupplement-asof-Apr1-2019.pdf.
[164] *See* ISO Market Charge Code Matrix, *available at* http://www.caiso.com/market/Pages/Settlements/Default.aspx.

c. Resource Sufficiency – Sub Balancing Authority Area level

As discussed above,[165] Bonneville's balancing authority area will be evaluated as a whole for Resource Sufficiency on an hourly basis, with the results impacting its market participation. Though the balancing authority area will be evaluated in aggregate, there are multiple resources and Load Serving Entities (LSE) that can influence the outcome of those evaluations. Bonneville will consider developing policies to ensure it passes Resource Sufficiency evaluations as often as feasible.

These requirements may influence and/or be memorialized in the BP-22 and TC-22 cases.

d. Transmission Losses

As energy is physically delivered across a transmission system there is a natural degradation, or "loss," that occurs due to 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 and what is "lost." Bonneville currently requires transmission customers to either designate to return transmission losses in kind (*e.g.*, with a physical delivery of energy) 168 hours (one week) later or settle them financially.

The EIM automatically dispatches incremental losses (above base schedules, which include losses) as part of its optimized dispatch. The EIM also creates a real-time marginal price for those losses at the time of their delivery. Bonneville will discuss with stakeholders the extent to which the EIM's handling of losses should lead to changes in Bonneville's current practices regarding transmission losses, or what new opportunities are available for a more efficient repayment of losses. This may include the potential for moving to a practice in which losses are only settled financially instead of a physical repayment. Decisions in this process will likely influence and/or be memorialized in the BP-22 and TC-22 cases.

e. Non-federal Resource Participation Requirements

As discussed above, Bonneville plans to utilize the "Big-10" FCRPS projects—aggregated into three separate resources—as its own Participating Resources. Bonneville will also need to develop requirements to provide the owners/operators of non-federal resources within the Bonneville balancing authority area the opportunity to act as Participating Resources.

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[165] *See* section III.e.7.

These requirements may cover topics such as technical requirements, timing, and impacts on RS evaluations. Decisions in this process will likely influence and/or be memorialized in the BP-22 and TC-22 cases.

f. Settlements/Billing (Mechanics)

As discussed above in issue V.b, if Bonneville joins the EIM as an EIM Entity, Bonneville will need to decide whether and how to allocate the CAISO's charges and credits to Bonneville's transmission customers. If Bonneville decides to allocate some or all of the EIM charges and credits to its customers, Bonneville will need to decide how to bill its customers.

The CAISO's billing process is very different from Bonneville's current billing processes. Bonneville bills its customers monthly; the CAISO bills its customers weekly. The timeline for disputes under Bonneville's agreements is relatively flexible. Disputes of a CAISO bill must be received within 22 business days after receiving a settlement recalculation statement or the disputes is deemed waived. Bonneville does not routinely revise a final monthly bill and, if it occurs, does so for a particular situation; the CAISO performs multiple recalculations of an invoice before finally closing out the settlement statement 36 months after the fact.

The billing and settlement mechanics policy process in Phase III will be closely linked with the policy process on allocation of EIM charge codes.

g. Data Submission Requirements

Efficient functioning of the EIM is dependent on it having timely and accurate information. As such, Bonneville will need to provide a significant quantity of data regarding its EIM balancing authority area, including load and generation information from Bonneville's customers. Much of this data exists in various formats today, but Bonneville must ensure it has reliable and timely access for the EIM to function properly.

Bonneville's process will include discussions with its customers regarding the content, delivery, and timing of data needed for Bonneville to operate an EIM balancing authority area. This data, along with its timing and delivery, will include the submission of base schedules, outages, and meter data.

h. Metering Requirements

Physical meter data for generators and interchange is critical for accurate EIM settlements. The CAISO provides guidance and minimum standards for the submission of meter data for the EIM Entity and Participating Resource Scheduling Coordinator but Bonneville must develop metering requirements for the balancing authority area and submit them in a settlement quality meter data plan. This plan will be applicable to all parties in the balancing authority area, not just Bonneville. Discussions on this issue will include the quality and granularity of data as well as the submission of the data.

VI. Conclusion

Bonneville seeks comment on the proposed decisions described in this document. Please submit comments by July 22, 2019, online at www.bpa.gov/comments. Stakeholder comments will be addressed in the Record of Decision, in which Bonneville will make a decision on whether to sign the EIM Implementation Agreement and move forward toward joining the EIM, as described in section II.

Attachment B

Bonneville Power Administration
Energy Imbalance Market Benefits Study

Final Report

Attachment B

Bonneville Power Administration Energy Imbalance Market Benefits Study

Final Report

June 18, 2019

Energy+Environmental Economics

Attachment B

Bonneville Power Administration Energy Imbalance Market Benefits Study

Final Report

June 18, 2019

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1 Overview of Benefits Study

Bonneville Power Administration (BPA) retained Energy and Environmental Economics, Inc. (E3) to study the potential economic benefits of BPA's participation in the Western Energy Imbalance Market (EIM), drawing on E3's experience performing similar benefits studies for other BAAs across the West. The goal of the benefits study was to estimate the benefit of BPA's participation in EIM using an industry standard EIM benefits modeling approach, customized to reflect the specific constraints and capabilities of BPA's system. E3 worked closely with BPA staff to define these input data and assumptions for representing BPA's system to best characterize both (1) the potential dispatch benefits under different price scenarios and subject to sensitivities in price regimes, hydro flexibility and operations as well as (2) the potential transmission benefits that BPA could realize through EIM participation.

Across the scenarios evaluated, this study found average annual gross dispatch benefits to BPA are shown in Table 1. Additional sensitivities relative to the Northwest Midpoint/Base Scenario are also shown in Table 1. We discuss the potential benefits of EIM as a complementary transmission tool for (1) transmission schedule curtailments and (2) as a platform for economically enabling non-wires solutions to moderately sized transmission constraints.

Table 1. Gross Dispatch Benefits for Scenarios and Sensitivities

	Average Revenue ($ million)	Annual Revenue ($ million)		
Scenarios & Sensitivities		**2016**	**2017**	**2018**
PSEI Price Scenario	**36.1**	43.6	33.0	31.6
PACW Price Scenario	**40.4**	54.7	39.9	26.7
BPAT Price Scenario (Initial Scenario)	**48.9**	48.0	49.9	48.9
NW Midpoint/Base Scenario (PGE Price)	**39.2**	**49.5**	**39.9**	**28.2**
Reduced Price Volatility Sensitivity	**35.3**	44.9	36.1	24.8
California GHG Compliance Sensitivity	**34.6**	45.6	34.5	23.8
FRST-Only Participation Sensitivity	**24.4**	32.3	25.4	15.6
Higher Success Rate Sensitivity	**47.1**	59.4	47.8	34.0

2 Gross Dispatch Benefits

2.1 Modeling Methodology

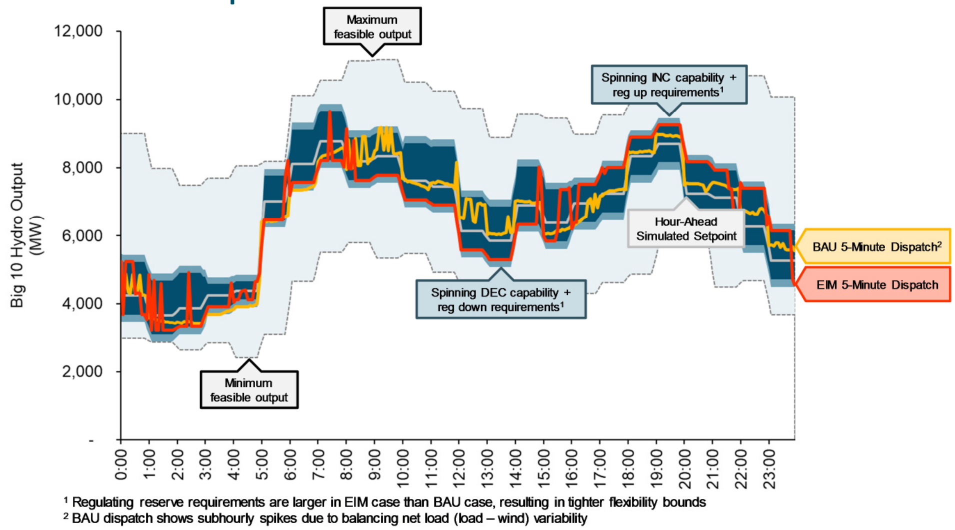
E3 developed scenarios for estimating the gross EIM dispatch benefits from BPA purchasing and selling energy as an EIM participant. E3 modeled these benefits using an industry-standard price-taker PLEXOS methodology employed in E3's previous EIM benefits studies, together with actual BPA data and CAISO-reported EIM prices for calendar years 2016-2018. In these scenarios, the following conservative modeling assumptions were used to isolate the benefits of BPA operations alone:

+ Historical Big 10 projects spinning capability[1, 2]
  (Combination of Big 6 projects feasible min/max output and residual Big 10 INC/DEC spin capacity, as illustrated in **Section 4.1**)
+ 24-hour energy neutrality (to avoid hydraulic management issues)
+ All non-Big-10 generators in BPA's BAA treated as fixed subhourly
+ 75% success rate applied to calculate EIM benefits to offset PLEXOS model's perfect foresight within each dispatch day

[1] Limiting participation to historical spinning capability also reduces the amount of additional wear-and-tear due to subhourly redispatch associated with the EIM benefits estimated in this study.
[2] Historical spinning capability resulted in BPA failing the flexible ramping sufficiency test (FRST) about 15% of intervals. In these intervals, no EIM benefits are assigned; in practice, should BPA choose to join, the Big 10 Hydro would be scheduled differently to ensure that the FRST was passed the vast majority of the time.

Figure 1 shows how these constraints combine to determine the flexibility available for subhourly dispatch in both the Business-As-Usual (BAU) and EIM cases. Under the BAU case, the subhourly flexibility is used to meet BPA's BAA net load variability and forecast error, while in the EIM case, the market is both a source and sink for economic flexibility. For example, when market prices are low, EIM purchases may be used instead of hydro dispatch to serve INC needs, while when prices are high hydro INC flexibility may be incremental sold into the EIM to increase revenues. Similar logic applies for DEC flexibility.

Figure 1. Example of Big 10 Subhourly Flexibility Under Business-As-Usual (BAU) and EIM Dispatch[3]



2.2 Northwest Price Scenarios

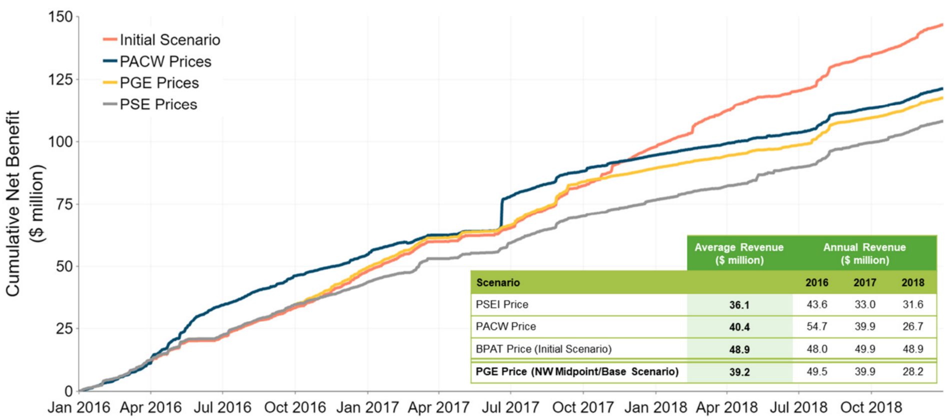
We developed four Northwest Price Scenarios to illustrate the gross dispatch benefits of BPA's participation subject to exposure to various historical EIM prices in the region (see **Section 4.3** for summary statistics on Northwest prices). This gross dispatch benefit is calculated as the incremental net revenue (sales revenue – purchase cost) that BPA can achieve by transacting in the 15- and 5-minute EIM markets.

The Northwest Midpoint/Base Scenario used historical DGAP_PGE-APND prices from 2016 through 2018. We also assumed the same hydrological conditions, resource output, and loads within BPA's Balancing Authority Area footprint for

[3] See **Section 4.1** for enlarged version of this graphic.

this period. This scenario showed gross dispatch benefits of **$39 million/year** on average over the 3 years due to BPA's participation in EIM during the historical years simulated. The effect of a broader range of Northwest EIM prices on gross dispatch benefits is shown below, which reflects the impact of different pricing conditions across the BAAs in the Northwest.

Figure 2. Cumulative Gross Dispatch Benefits for Northwest Price Scenarios[4]



	Average Revenue ($ million)	Annual Revenue ($ million)		
Scenario		**2016**	**2017**	**2018**
PSEI Price	**36.1**	43.6	33.0	31.6
PACW Price	**40.4**	54.7	39.9	26.7
BPAT Price (Initial Scenario)	**48.9**	48.0	49.9	48.9
PGE Price (NW Midpoint/Base Scenario)	**39.2**	49.5	39.9	28.2

Across these scenarios, we show that available hydro flexibility is a major factor in EIM value for BPA. In late spring/early summer months, where hydro flexibility is most constrained, the model shows that EIM benefits are lowest. See **Section 4.5** for monthly revenues for each scenario.

For the remainder of the study, the scenario using PGE prices (DGAP_PGE-APND) is considered as the **NW Midpoint/Base Scenario**.

[4] BPA's Northwest neighbors' price points span over times prior to these entities joining the EIM as well as after joining the EIM. PACW joined the EIM prior to the modeled historical period, PSE joined the EIM in the fall of 2016 while PGE joined the EIM in fall of 2017, which will have affected their prices and are reflected in these benefits.

2.3 Sensitivities

In addition to the Northwest price scenarios, we analyzed four sensitivities based on the **NW Midpoint/Base Scenario** to independently illustrate the impact of different key assumptions. See **Section 4.3** for a qualitative discussion on these assumptions. The results of these sensitivities are shown in **Figure 1**. The sensitivities we considered were as follows:

+ **Reduced Intra-Hour Price Volatility**
  In this sensitivity, we reduce intra-hour 15- and 5-minute EIM price volatility by 50% such that modeled EIM prices are 50% closer to their hourly average than observed by CAISO in the historical record for the DGAP_PGE-APND pricing node. This is meant to estimate the economic impact of a situation where subhourly volatility decreases relative to historical observations and/or the market is relatively "shallow" at extreme prices. However, this sensitivity preserves the diurnal pattern of prices. This sensitivity tends to reduce prices and the benefits.

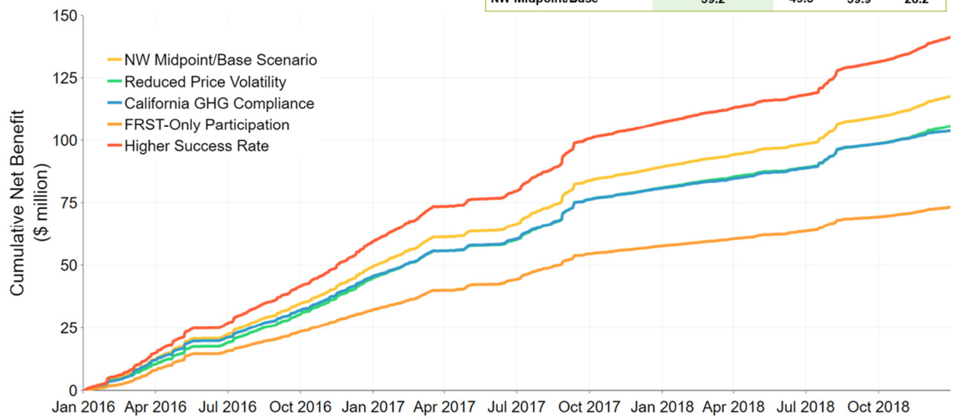
+ **California GHG Fee Compliance**
  In this sensitivity, we attempt to model the impact of BPA's inability to pay for GHG allowances associated with unspecified imports into California. To model this, we penalize the model for selling in intervals where historical EIM prices showed a nonzero marginal cost of carbon component, which is indicative of non-California entities as a whole importing GHG-containing energy into California via the EIM. This is consistent with BPA selling energy to non-California entities in the EIM and not being able to get the price premium associated with the cost of GHG compliance in California. This sensitivity tends to reduce the benefits.

+ **FRST-Only Participation**
  In this sensitivity, we further reduce BPA's Big 10 Hydro participation in EIM to the minimum flexibility needed to pass the Flexible Resource Sufficiency Test (FRST). This limit was determined to be the most representative assumption for minimum flexibility. This sensitivity tends to reduce the benefits.
+ **Higher Success Rate**
  In this sensitivity, we assume that the success rate for BPA's participation in EIM increases from 75% to 90%. Across the other scenarios and sensitivities, we assume a success rate of 75% to derate the benefits associated with the modeled participation. This success rate may be less than 100% due to imperfect foresight during actual operations. This can encompass situations such as if BPA's bids do not successfully clear the EIM in all intervals, if there is limited market depth at a given price point (e.g., the price decreases due to BPA's marginal participation), or if there are unforeseen hydro constraints that were not captured in the historical spinning capability. This sensitivity tends to increase the benefits.

The first three sensitivities above estimated that benefits would be reduced by between **$4-15 million/year** relative to the NW Midpoint/Base Scenario, reflecting a wider range of plausible pricing and flexibility assumptions for BPA's participation. Meanwhile, increasing success rate increases benefits by the same percentage amount.

Figure 3. Cumulative Gross Dispatch Benefits for Sensitivities

Scenario	Average Revenue ($ million)	Annual Revenue ($ million) 2016	2017	2018
Reduced Price Volatility	**35.3**	44.9	36.1	24.8
California GHG Compliance	**34.6**	45.6	34.5	23.8
FRST-Only Participation	**24.4**	32.3	25.4	15.6
Higher Success Rate	**47.1**	59.4	47.8	34.0
NW Midpoint/Base	**39.2**	**49.5**	**39.9**	**28.2**



3 Transmission Benefits

Transmission investments will continue to be an important part of BPA's planning efforts; for example, transmission will be needed to connect new generators and loads as well as replace aging infrastructure. However, in certain situations EIM can provide viable benefits to BPA's transmission customers.

E3 and BPA staff defined two ways in which EIM participation could provide benefits to BPA's transmission customers. These benefits come from the EIM's **security-constrained economic dispatch** (SCED), which optimally manages congestion across the entire market footprint. In both cases, the EIM is useful for addressing short-term, moderate-sized needs and is complementary to the planning and operational tools that BPA employs today:

+ Transmission Curtailment
+ EIM as a Non-Wires Solution

In situations where system operating limits are at risk of being exceeded, BPA currently may choose to curtail transmission schedules to maintain reliability. Under current practice, schedules are curtailed pro-rata according to NERC Curtailment priorities, which is non-optimal, resulting in more MW of curtailed schedules that is needed to address the local constraint. In contrast, EIM's SCED is designed to incorporate all system operating limits directly into the dispatch algorithm, creating a lowest-cost dispatch across the entire market footprint that maintains operational feasibility. With the larger market, there is also a larger pool of available resources to maintain system balance, providing a more precise and effective tool for addressing moderately sized transmission constraints.

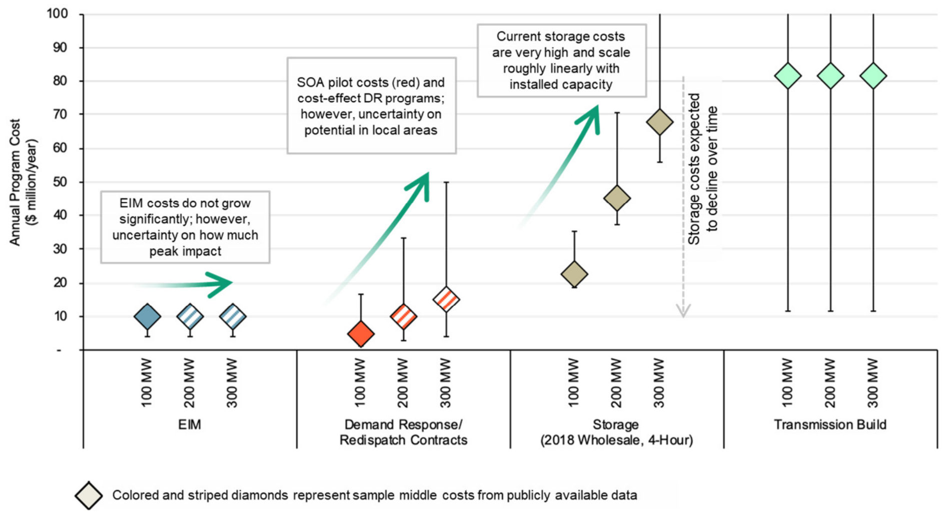
Table 2. Characteristics of Various Transmission Planning Solutions

	EIM	DR	Storage	Transmission Build
Generation Capacity Value	No	Yes	Yes	No
Energy Value	Yes	Yes	Yes	No
Transmission Capacity Value	Low	Low	Medium	High
Congestion Area	Wide	Local	Local	Local
Congestion Value	High	Medium	Medium	High
Effort to Provision	Low	Medium	Medium	High
Levelized Costs	$	$$	$$$	$$
Call Option Timing	N/A	0-2 Days	0-2 Days	N/A
Response Time	8-12 Minutes	0-18 Hours	0-18 Hours	N/A
Duration	5-240 Minutes	1-360 Minutes	1-480 Minutes	30-50 Years
Uses	Load Service Imbalance Energy Economic Dispatch Congestion Management Renewable Integration Energy Optimization	Load Service Peak Shaving Congestion Management Renewable Integration Ancillary Services	Load Service Peak Shaving Congestion Management Renewable Integration Ancillary Services Energy Optimization	Load Service Renewable Integration

Table 1 describes the characteristics of various planning solutions for addressing transmission flow relief. Certain solutions provide multiple uses and value streams; for example, demand response and storage can provide generation capacity value while EIM and new transmission do not. Due to the subhourly and voluntary nature of EIM, it cannot be relied upon for hourly resource sufficiency or long-term resource adequacy needs, so investments in other resources within BPA's territory will still be necessary. Similarly, some solutions are faster responding (such as EIM being able to redispatch within minutes compared to day-ahead demand response calls), while others (such as transmission build) are able provide flow relief over multiple decades. No single

solution described above can provide all the benefits at the lowest for all transmission needs at the lowest cost; the comparison emphasizes that adding new tools to BPA's planning toolkit provides yet another economic solution that can be deployed to serve customers.

Figure 4. Gross Annual Program Cost for Various Transmission Planning Solutions at Illustrative Flow Relief Levels



Using publicly available cost information[5], **Figure 4** compares the **estimated gross annual program costs**[6] for each of the solutions discussed, scaled to illustrative flow relief levels of 100 MW, 200 MW, and 300 MW. The figure shows EIM as possibly providing more than 100 MW of flow relief (dashed

[5] EIM levelized costs come from latest BPA implementation estimates, levelized over 20 years at an 8% discount rate. Redispatch contract costs are based on the South-of-Allston pilot. Demand response cost ranges come from latest BPA DR potentials study and are based on upfront implementation costs; Bonneville expects that levelized costs of an ongoing DR program would be significantly lower than those from the time-limited SOA pilot. Storage costs come from Lazard's Levelized Cost of Storage 4.0 study; these estimates may differ from near-term costs for battery storage projects in BPA's territory. Transmission costs come from recent BPA (proposed) projects.

[6] The **net annual program costs** for various solutions may be lower when considering the other sources of value that each solution can provide. For example, demand response and storage have unique purposes outside of congestion management, such as generation capacity value, which can offset some of the gross program costs.

diamonds) for almost no incremental cost; however, as the need increases, the uncertainty of whether EIM can provide that required relief increases as well. The flatness of gross EIM program costs contrasts with the localized nature of other transmission solutions, which generally scale with size and/or number of load relief areas.

Table 3. Illustrative Quantitative Example of Annual Program Costs

Batteries and Redispatch Case		EIM Case	
100 MW battery @ $226/kW-year	$22.6 million/year	$10 million/year (levelized startup and ongoing costs)	$10 million/year
100 MW Redispatch Contract / DR @ $50/kW-year[7]	+ $5.0 million/year		
Annual Cost	**= $27.6 million/year**		**= $10 million/year**

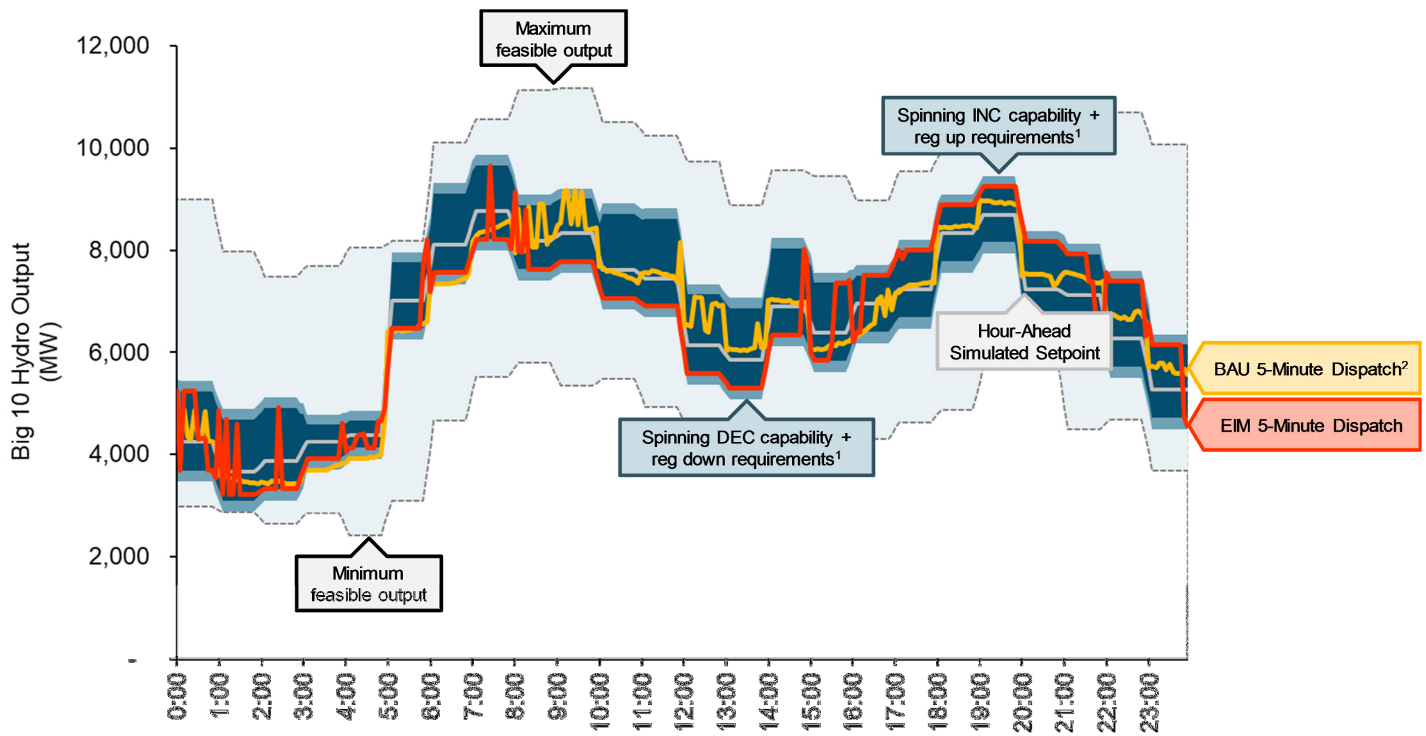
To illustrate the comparison of gross program costs, **Table 3** presents an example of two potential flowgates, each needing 100 MW of intra-hour flow relief. If we assume that EIM can provide the flow relief needed, the total levelized cost of using EIM is $10 million/year. In contrast, under a business-as-usual case, where BPA may procure a mix of batteries, demand response, and redispatch contracts, the gross program cost would be $27.6 million/year at current costs. Scaling these cases to twice the size—4 flowgates or 200 MW—would result in $55.2 million/year in cost under the example Batteries and Redispatch Case and $10 million/year in the EIM Case. Both cases provide other benefits to BPA's operations that could lower the net cost associated with

[7] The SOA Redispatch Pilot program provided approximately 100 MW of flow relief for ten 4-hour events per year, during summer weekday afternoons, from 200 MW of incremental and 200 MW of decremental capacity based on a prior pre-schedule call option requirement for manual deployment. A longer term (5-7 year) program may have been less expensive on an annual basis.

providing flow relief; however, this simple quantitative example illustrates that the costs associated with EIM (regardless of how costs are allocated) can be lower than alternative solutions for small- to moderately-sized needs.

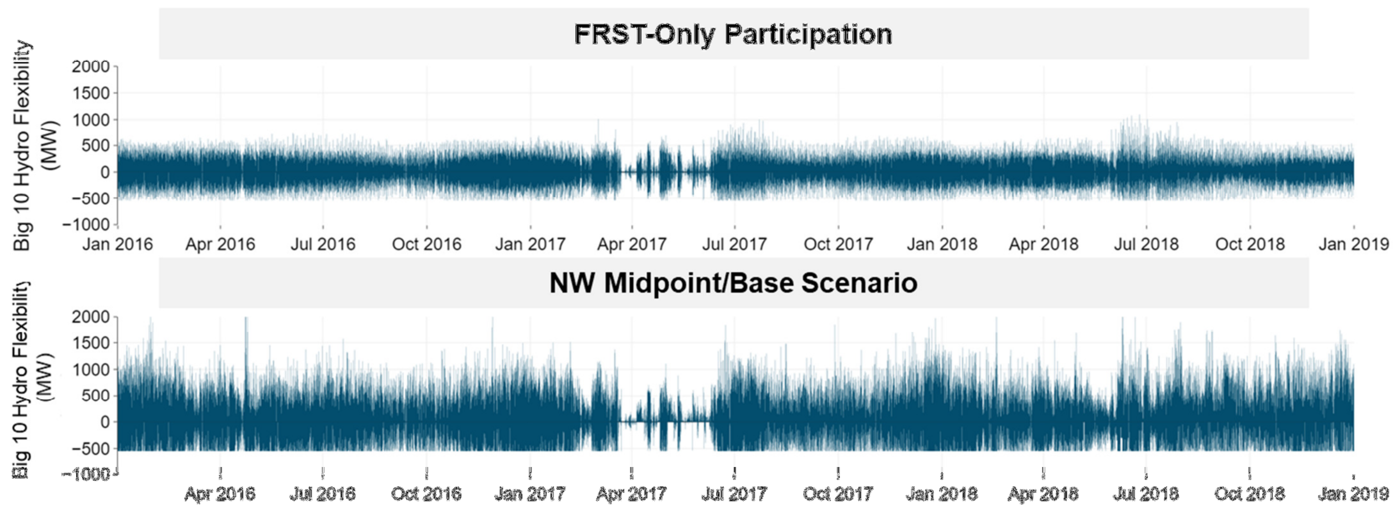
4 Appendix

4.1 Example of Big 10 Subhourly Flexibility Under Business-As-Usual (BAU) and EIM Dispatch



[1] Regulating reserve requirements are larger in EIM case than BAU case, resulting in tighter flexibility bounds
[2] BAU dispatch shows subhourly spikes due to balancing net load (load – wind) variability

4.2 Big 10 Hydro Spinning Capability Available for EIM Participation



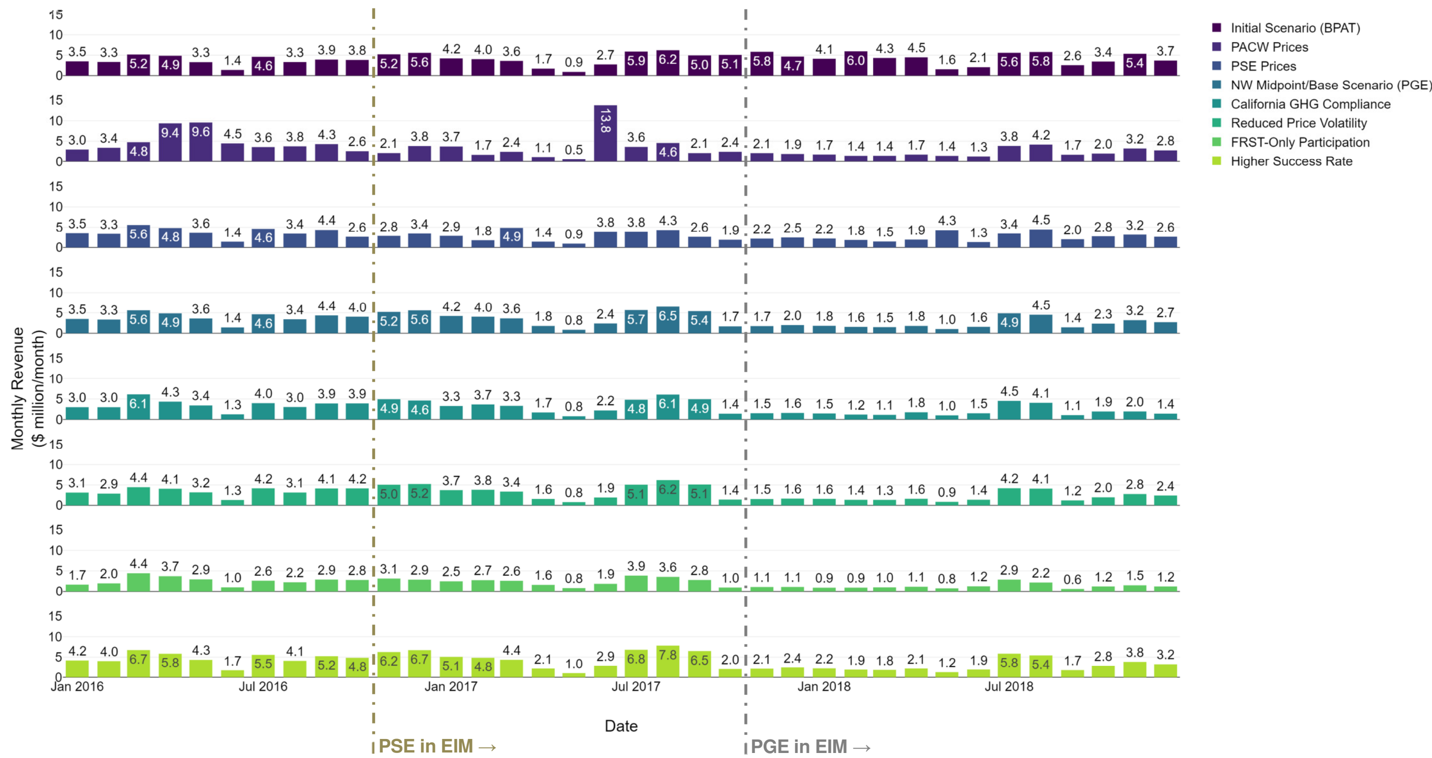
4.3 Northwest EIM Price Statistics for 2016-2018 Historical Period

	DGAP_BPAT-APND		DGAP_PACW-APND		DGAP_PGE-APND		DGAP_PSEI-APND	
EIM Market	***15-Minute***	***5-Minute***	***15-Minute***	***5-Minute***	***15-Minute***	***5-Minute***	***15-Minute***	***5-Minute***
Mean ($/MWh)	29.31	28.48	24.37	21.94	26.57	25.86	24.68	23.46
Median ($/MWh)	26.01	24.24	22.66	21.56	24.64	23.22	23.58	22.44
Max ($/MWh)	1,189.40	1,112.64	1,004.51	1,184.21	1,061.71	1,256.62	1,104.54	1,477.32
Min ($/MWh)	-176.44	-371.9	-1,892.05	-1,037.59	-155.67	-374.77	-201.03	-321.19
>$100/MWh (hours)	189	272	103	103	118	197	110	139
<-$100/MWh (hours)	1	6	12	44	2	9	46	69

4.4 Sensitivity Assumptions

Sensitivity	NW Midpoint Assumption	More Optimistic	More Conservative
Success Rate	• 75%	• Higher success rate: Better foresight on hydro operations and success in being awarded bids at modeled price	• Lower success rate: Hydro is more constrained than expected or bids are not successfully awarded to BPA
Hydro Flexibility	• Actual "Big 10" Hydro INC/DEC spinning capability • Daily hydro energy balance • BPA meets FRST in all hours	• Use hydro capability beyond spinning capability on "Big 10" Hydro • Optimize FCRPS to increase available capability for EIM transactions • Allow hydro to be balanced across multiple days	• Limiting available spinning capability for EIM participation e.g. no participation beyond what is required for FRST only
EIM Price	• 2016-2018 PGE prices	• Historical DGAP_BPAT-APND prices are more volatile	• PSE prices are on average lower and less volatile • NW average prices would decrease overall price volatility
EIM Intra-Hour Price Volatility	• Actual volatility of 2016-2018 PGE prices	• Price volatility within the hour will stay the same	• Price volatility within the hour is reduced due to higher EIM participation
California GHG Fee	• No marginal cost of GHG considered in EIM prices	• n/a	• EIM prices are reduced when increasing generation during intervals of nonzero marginal cost of GHG

4.5 Monthly Revenues by Scenario



4.6 Average Simulated EIM Transfers by Scenario

	Sales (INC)		Purchases (DEC)	
Market	***15-Minute*** (average MW)	***5-Minute*** (average MW)	***15-Minute*** (average MW)	***5-Minute*** (average MW)
BPAT Prices (Initial Scenario)	232.2	164.6	233.7	169.9
PACW Prices	237.0	174.2	240.2	192.1
PSE Prices	230.8	164.2	233.2	168.7
NW Midpoint/Base Scenario	**231.9**	**161.4**	**232.6**	**166.0**
California GHG Compliance	202.6	132.5	203.3	137.3
Reduced Price Volatility	228.8	156.5	227.5	160.1
FRST-Only Participation	158.0	123.5	158.8	128.1
Higher Success Rate	231.9	161.4	232.6	166.0

Attachment C

Draft Implementation Agreement

ENERGY IMBALANCE MARKET IMPLEMENTATION AGREEMENT

This Implementation Agreement ("Agreement") is entered into as of [DATE], by and between the United States of America, Department of Energy, acting by and through the Bonneville Power Administration ("Bonneville"), and the California Independent System Operator Corporation, a California nonprofit public benefit corporation ("ISO"). Bonneville and the ISO are sometimes referred to in the Agreement individually as a "Party" and, collectively, as the "Parties."

RECITALS

A. WHEREAS, Bonneville is a federal power marketing administration that markets electric power from multiple generating resources, including but not limited to the Federal Columbia River Power System owned and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation, and the Columbia Generating Station owned and operated by Energy Northwest;

B. WHEREAS, Bonneville also owns and/or operates a high voltage transmission system in the Pacific Northwest (the Federal Columbia River Transmission System) and a balancing authority area;

C. WHEREAS, Bonneville has determined there is an opportunity to secure benefits for Bonneville's customers through improved dispatch and operation of the Federal Columbia River Power System and through the efficient use and continued reliable operation of existing and future transmission facilities and desires to participate in the energy imbalance market operated by the ISO ("EIM");

D. WHEREAS, the ISO has determined there are benefits to ISO market participants through greater access to energy imbalance resources in real-time and through the efficient use and reliable operation of the transmission facilities and markets operated by the ISO, and desires to expand operation of the EIM to include Bonneville;

E. WHEREAS, Bonneville acknowledges that the rules and procedures governing the EIM are set forth in the provisions of the ISO tariff as filed with the Federal Energy Regulatory Commission ("FERC") and that participation in the EIM requires corresponding revisions to Bonneville's rate schedules and Open Access Transmission Tariff ("Bonneville Tariff");

F. WHEREAS, Bonneville's decision to participate voluntarily in the EIM is within Bonneville's sole discretion, and Bonneville will only participate in the EIM so long as such participation is on a voluntary basis and on terms and conditions acceptable to Bonneville, including Bonneville's unilateral right to terminate this Agreement as set forth below;

G. WHEREAS, Bonneville's EIM implementation and participation is limited to the scope of the EIM at the time this Agreement becomes effective pursuant to Section 1 below. Bonneville is under no obligation to participate in any expanded EIM markets (*e.g.*, day-ahead); and

H. WHEREAS, the Parties are entering into this Agreement to set forth the terms upon which the ISO will timely configure its systems to incorporate Bonneville into the EIM ("Project") on or before March 1, 2022 ("Implementation Date").

NOW THEREFORE, in consideration of the mutual covenants contained herein, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

AGREEMENT

1. Effective Date, Term, and Bonneville's Non-Jurisdictional Status.

(a) This Agreement shall become effective upon the date the Agreement is accepted, approved or otherwise permitted to take effect by FERC, without condition or modification unsatisfactory to either Party ("Effective Date").

(b) In the event FERC requires any modification to the Agreement or imposes any other condition upon its acceptance or approval of the Agreement, each Party shall have ten (10) business days to notify the other Party that any such modification or condition is unacceptable to that Party. If no Party provides such notice, then the Agreement, as modified or conditioned by FERC, shall take effect as of the date determined under Section 1(a). If either Party provides such notice to the other Party, the Parties shall take any one or more of the following actions: (i) meet and confer and agree to accept any modifications or conditions imposed by such FERC order; (ii) jointly seek further administrative or legal remedies with respect to such FERC order, including a request for rehearing or clarification; or (iii) enter into negotiations with respect to accommodation of such FERC order, provided however, if the Parties have not agreed to such an accommodation within thirty (30) calendar days after the date on which such FERC order becomes a final and non-appealable order, such order shall be deemed an adverse order and the Parties shall have no further rights and obligations under the Agreement.

(c) The term of the Agreement ("Term") shall commence on the Effective Date and shall terminate upon the earliest to occur of (1) the date all necessary revisions to the Bonneville Tariff, Bonneville's rate schedules, and the ISO tariff necessary for the commencement of Bonneville's participation in the EIM have taken effect (when the market becomes financially binding on transactions within Bonneville's balancing authority area); (2) termination in accordance with Section 2 of this Agreement; or (3) such other date as mutually agreed to by the Parties ("Termination Date").

(d) This Agreement shall automatically terminate on the Termination Date and shall have no further force or effect, provided that the rights and obligations set forth in Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect as provided therein.

(e) The ISO acknowledges that Bonneville is a non-jurisdictional utility described in section 201(f) of the Federal Power Act, 16 U.S.C. 824(f), and respects Bonneville's interest in remaining so. Nothing in this Agreement or subsequent EIM-related agreements is intended to create additional FERC jurisdiction for Bonneville, nor shall it be construed in a manner that creates additional FERC jurisdiction for Bonneville.

2. Termination.

(a) The Parties may mutually agree to terminate this Agreement in writing at any time. In addition, either Party may terminate this Agreement in its sole discretion after conclusion of the negotiation period in Section 2(b) or as provided in Section 2(d) or 2(e) as applicable.

(b) If either the ISO or Bonneville seeks to unilaterally terminate this Agreement, it must first notify the other Party in writing of its intent to do so ("Notice of Intent to Terminate") and engage in thirty (30) calendar days of good faith negotiations in an effort to resolve its concerns. If the Parties successfully resolve the concerns of the Party issuing the Notice of Intent to Terminate, the Party that issued such notice shall notify the other Party in writing of the withdrawal of such Notice ("Notice of Resolution").

(c) At the time the Notice of Intent to Terminate is provided, or any time thereafter unless a Notice of Resolution is issued, Bonneville may provide written notice directing the ISO to suspend performance on any or all work on the Project for a specified period of time ("Notice to Suspend Work"). Upon receipt of a Notice to Suspend Work, the ISO shall: (1) discontinue work on the Project; (2) place no further orders with subcontractors related to the Project; (3) take commercially reasonable actions to suspend all orders and subcontracts; (4) protect and maintain the work on the Project; and (5) otherwise mitigate Bonneville's costs and liabilities for the areas of work suspended. The ISO will not invoice Bonneville pursuant to Section 4(c) of this Agreement for any milestone payment following the issuance of a Notice to Suspend Work. To the extent a Notice of Resolution is issued pursuant to Section 2(b), the Notice to Suspend Work in effect at the time shall be deemed withdrawn and the ISO shall be entitled to invoice Bonneville for any milestone completed as specified in Section 4(c) of this Agreement and Bonneville shall pay such invoice pursuant to Section 4.

(d) Any time after thirty (30) calendar days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a Notice of Resolution, the ISO may terminate this Agreement by providing written notice to Bonneville that it is terminating this Agreement ("Termination Notice") effective immediately. The ISO may terminate this Agreement under the terms of this Section 2(d) at its sole discretion for any reason.

(e) Any time after thirty (30) calendar days from the date of the Notice of Intent to Terminate under Section 2(b), issued by either Party, and prior to the date of a

Notice of Resolution, Bonneville may terminate this Agreement by providing written notice to the ISO that it is terminating this Agreement ("Termination Notice") effective immediately. Bonneville may terminate this Agreement under the terms of this Section 2(e) at its sole discretion for any reason.

(f) In the event this Agreement is terminated by either or both of the Parties pursuant to its terms, this Agreement will become wholly void and of no further force and effect, without further action by either Party, and the liabilities and obligations of the Parties hereunder will terminate, and each Party shall be fully released and discharged from any liability or obligation under or resulting from this Agreement as of the date of the Termination Notice provided in Section 2(d) or 2(e), as applicable, notwithstanding the requirement for the ISO to submit the filing specified in Section 2(g). Notwithstanding the foregoing, the rights and obligations set forth in Sections 5 and 6 shall survive the termination of this Agreement and remain in full force and effect as specified in Sections 5 and 6, and any milestone payment obligation pursuant to Section 4(c) that arose prior to the Termination Notice in accordance with Section 2(d) or 2(e) shall survive until satisfied or resolved in accordance with Section 11.

(g) The Parties acknowledge that the ISO is required to file a notice of termination with FERC.

3. Implementation Scope and Schedule.

(a) The Parties shall complete the Project as described in Exhibit A, subject to modification only as described in Section 4(e) below.

(b) The Parties shall undertake the activities described in Exhibit A with the objective of completing the Project and implementing the EIM no later than the Implementation Date, including all milestones listed under Exhibit A for the Implementation Date, subject to modification only as described in Section 3(c) below.

(c) Either Party may propose a change in Exhibit A or the Implementation Date to the other Party. If a Party proposes a change in Exhibit A or the Implementation Date, the Parties shall negotiate in good faith to attempt to reach agreement on the proposal and any necessary changes in Exhibit A and any other affected provision of this Agreement, provided that any change in Exhibit A, or any change to the Implementation Date, must be mutually agreed to by the Parties. The agreement of the Parties to a change in Exhibit A, or a change to the Implementation Date, shall be memorialized in a revision to Exhibit A, which will then be binding on the Parties and shall be posted on the internet web sites of the ISO and Bonneville, without the need for execution of an amendment to this Agreement. Changes that require revision of any provision of this Agreement other than Exhibit A shall be reflected in an executed amendment to this Agreement and filed with FERC for acceptance.

(d) At least once per calendar month during the Term, the Parties' Designated Executives, or their designees, will meet telephonically or in person (at a mutually agreed to location) to discuss the status of the performance of the tasks necessary to achieve the milestones in Exhibit A and the continued appropriateness of Exhibit A to ensure that the Project can meet the Implementation Date. For purposes of this section, "Designated Executive" shall mean the individual identified in Section 8(g), or her or his designee or successor.

4. Implementation Charges, Invoicing and Milestone Payments.

(a) As itemized in Section 4(c) below, Bonneville shall pay the ISO a fixed fee of $1,870,000 for costs incurred by the ISO to implement the Project ("Implementation Fee"), subject to completion of the milestones specified in Section 4(c) and subject to adjustment only as described in Section 4(b).

(b) The ISO will provide prompt written notice to Bonneville when the sum of its actual costs through the date of such notice and its projected costs to accomplish the balance of the Project exceed the Implementation Fee. The Implementation Fee shall be subject to adjustment only by mutual agreement of the Parties if the Parties agree to a change in Exhibit A, or a change to the Implementation Date, in accordance with Section 3(c) and the Parties agree that an adjustment to the Implementation Fee is warranted in light of such change.

(c) For each milestone described in Exhibit A, the ISO shall invoice Bonneville for 1/6th of the Implementation Fee as follows:

i. $311,650 upon the Effective Date as described in Section 1 of this Agreement for Milestone 1;

ii. $311,650 upon completion of detailed Project Management Plan for Milestone 2;

iii. $311,650 upon ISO promotion of market model including the Bonneville area market data to the market simulation non-production system, and allowing Bonneville to start connectivity testing and exchange data in advance of market simulation for Milestone 3;

iv. $311,650 upon the conclusion of day-in-life simulation, and start of EIM market simulation for Milestone 4;

v. $311,700 upon the start of full 24/7 parallel operations for Milestone 5; and

vi. $311,700 upon the first production Bonneville EIM trade date for Milestone 6.

(d) Following the completion of each milestone identified in Section 4(c)(i) through (vi), the ISO will deliver to Bonneville an invoice which will show the amount due. The invoice shall contain information specified in 5 C.F.R. § 1315.9(b) and shall contain reasonable documentation supporting the completion of the milestone being invoiced. Bonneville shall pay the invoice no later than forty-five (45) calendar days after the date of receipt. Any milestone payment past due will accrue interest, per annum, calculated in accordance with 5 C.F.R. § 1315.10.

(e) If a milestone has not been completed as described in Section 4(c)(i), (ii), (iii), (iv), or (v) and in Exhibit A, as Exhibit A may have been modified in accordance with Section 3(c), the Parties shall negotiate in good faith an agreed upon change to the Project Delivery Dates (as defined in Exhibit A) consistent with Section 3(c) such that the timing of milestone payments in Section 4(c) can be adjusted to correspond to the updated Exhibit A.

(f) If Bonneville disputes any portion of any amount specified in an invoice delivered by the ISO in accordance with Section 4(c), Bonneville shall pay its total amount of the invoice when due, and identify the disputed amount and state that the disputed amount is being paid under protest. Any disputed amount shall be resolved pursuant to the provisions of Section 11. If it is determined pursuant to Section 11 that an overpayment or underpayment has been made by Bonneville or any amount on an invoice is incorrect, then (i) in the case of any overpayment, the ISO shall promptly return the amount of the overpayment (or credit the amount of the overpayment on the next invoice) to Bonneville; and (ii) in the case of an underpayment, Bonneville shall promptly pay the amount of the underpayment to the ISO. Any overpayment or underpayment shall include interest for the period from the date of overpayment, underpayment, or incorrect allocation, until such amount has been paid or credited against a future invoice calculated in the manner prescribed for calculating interest in Section 4(d).

(g) All costs necessary to implement the Project not provided for in this Agreement shall be borne separately by each Party, which in the case of the ISO will be recovered through rates as may be authorized by its regulatory authorities.

(h) All milestone payments required to be made under the terms of this Agreement shall be made to the account or accounts designated by the Party which the milestone payment is owed, by wire transfer (in immediately available funds in the lawful currency of the United States).

5. Confidentiality.

(a) All written or oral information received from the other Party in connection with this Agreement (but not this Agreement after it is filed with FERC) necessary to complete the Project and marked or otherwise identified at the time of communication by such Party as containing information that Party considers commercially sensitive or confidential shall constitute "Confidential Information" subject to the terms and conditions herein.

(b) If Bonneville publicly releases Bonneville's Confidential Information in connection with a public process or a regulatory filing, or if the ISO publicly releases the ISO's Confidential Information in connection with a public process or a regulatory filing, then the information released shall no longer constitute Confidential Information;

provided, however, that Confidential Information disclosed under seal (or in such other manner as to be treated confidentially) in connection with a regulatory filing shall retain its status as Confidential Information under this Agreement. In addition, Confidential Information does not include information that (i) is or becomes generally available to the public other than as a result of disclosure by either Party, its officers, directors, employees, agents, or representatives; (ii) is or becomes available to such Party on a non-confidential basis from other sources or their agents or representatives when such sources are not known by such Party to be prohibited from making the disclosure; (iii) is already known to such Party or has been independently acquired or developed by such Party without violating any of such Party's obligations under this Section 5; (iv) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, with regard to information for discussion at any stakeholder meetings or during the stakeholder process or with any regulatory authority; or (v) is the subject of a mutual written agreement between the Parties, including an agreement evidenced through an exchange of electronic or other communications, to allow for such disclosure and designation as non-confidential or public information on a case-by-case basis in accordance with Section 10 of this Agreement.

(c) The Confidential Information will be kept confidential by each Party and each Party agrees to protect the Confidential Information using the same degree of care, but no less than a reasonable degree of care, as a Party uses to protect its own confidential information of a like nature. Notwithstanding the preceding sentence, a Party may disclose the Confidential Information or portions thereof to those of such Party's officers, employees, partners, representatives, attorneys, contractors, advisors, or agents who need to know such information for the purpose of analyzing or performing an obligation related to the Project. Notwithstanding the foregoing, a Party is not authorized to disclose such Confidential Information to any officers, employees, partners, representatives, attorneys, contractors, advisors, or agents without (i) informing such officer, employee, partner, representative, attorney, contractor, advisor, or agent of the confidential nature of the Confidential Information and (ii) ensuring that such officer, employee, partner, representative, attorney, contractor, advisor, or agent is subject to confidentiality duties or obligations to the applicable Party that are no less restrictive than the terms and conditions of this Agreement. Each Party agrees to be responsible for any breach of this Section 5 by such Party or a Party's officers, employees, partners, representatives, attorneys, contractors, advisors or agents, subject to the limitations set forth in Section 6 below.

(d) In the event that a Party is required by a court of competent jurisdiction, applicable law, including, but not limited to, the Freedom of Information Act, 5 U.S.C. § 552, or regulatory authority (by rule, regulation, order, deposition, interrogatory, request for documents, data request issued by a regulatory authority, subpoena, civil investigative demand or similar request or process) to disclose any of the Confidential Information, such Party shall (to the extent legally permitted) provide the other Party with prompt written notice of such requirement so that the other Party may seek a protective order or other appropriate remedy and/or waive compliance with the terms of this Section 5. In the event that such protective order or other remedy is not obtained, the disclosing Party hereby waives compliance with the provisions hereof with respect to such Confidential Information. In such event, the Party compelled to disclose shall (i) furnish only that portion of the Confidential Information which is legally required to be furnished, and (ii) exercise reasonable efforts to obtain assurances that confidential treatment will be accorded the Confidential Information so furnished.

(f) Either Party may seek damages or other remedies permitted by applicable law if a Party breaches this Section 5, however, the Parties will first seek to resolve any dispute regarding disclosure arising under this Section 5 by mutual agreement, subject to the limitations set forth in Section 6 below.

(g) Upon written request by a Party, the other Party shall promptly return to the requesting Party or destroy all Confidential Information it received, including all copies of its analyses, compilations, studies or other documents prepared by or for it, that contain the Confidential Information in a manner that would allow its extraction or that would allow the identification of the requesting Party as the source of the Confidential Information or inputs to the analysis. Notwithstanding the foregoing, a Party shall not return or destroy the other Party's Confidential Information if a third party is seeking such information under section 5(d) of this Agreement, and neither Party shall be required to destroy or alter any computer archival and backup tapes or archival and backup files (collectively, "Computer Tapes"), provided that such Computer Tapes shall be kept confidential in accordance with the terms of this Agreement.

(h) Nothing in this Agreement shall be deemed to restrict either Party from engaging with third parties with respect to any matter and for any reason, specifically including the EIM, provided Confidential Information is treated in accordance with this Section 5.

(i) This Section 5, Confidentiality, applies for two years (24 months) after the Termination Date or the date of any expiration or termination of this Agreement.

6. Limitation of Liability.

(a) The Parties acknowledge and agree that, except as otherwise specified in Sections 4(f) and 6 (b) of this Agreement, neither Party shall be liable to the other Party for any claim, loss, cost, liability, damage or expense, including any direct damage or any special, indirect, exemplary, punitive, incidental or consequential loss or damage (including any loss of revenue, income, profits or investment opportunities or claims of third party customers), arising out of or directly or indirectly related to such other Party's decision to enter into this Agreement, such other Party's performance under this Agreement, or any other decision by such Party with respect to the Project.

(b) Claims for property damage, personal injury and death against Bonneville must be brought under the Federal Tort Claims Act, 28 U.S.C. 2671 et seq. Within the limitations of applicable law, the ISO shall be responsible for injuries and damages to third-parties caused by its negligence, intentional misconduct, or breach of this Agreement.

(c) The rights and obligations under this Section 6 shall survive the Termination Date and any expiration or termination of this Agreement.

7. Representation and Warranties.

(a) Representations and Warranties of Bonneville. Bonneville represents and warrants to the ISO as of the Effective Date as follows:

(1) It is duly formed under federal law.

(2) It has all requisite statutory authority necessary to carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(3) It has all necessary statutory authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized.

(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organic statutes; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms.

(b) Representations and Warranties of the ISO. The ISO represents and warrants to Bonneville as of the Effective Date as follows:

(1) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(2) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(3) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(4) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any governmental requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(5) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, regulatory authority, or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(6) All material governmental authorizations in connection with the due execution and delivery of, and performance by it of its obligations under this Agreement, have been duly obtained or made prior to the date hereof and are in full force and effect.

8. General Provisions.

(a) This Agreement, including Exhibit A and Exhibit B to this Agreement, constitutes the entire agreement between the Parties, and supersedes any prior written or oral agreements or understandings between the Parties, relating to the subject matter of this Agreement; provided, that nothing in this Agreement shall limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of each of the Parties as provided by any other agreement between the Parties, or by any statute or any other law or applicable court or regulatory decision by which such Party is bound.

(b) This Agreement may not be amended except in writing hereafter signed by both of the Parties; provided, however, the Parties may mutually agree to changes in Exhibit A in accordance with Section 4(e).

(c) Any waiver by a Party to this Agreement of any provision or condition of this Agreement must be in writing signed by the Party to be bound by such waiver, shall be effective only to the extent specifically set forth in such writing and shall not limit or affect any rights with respect to any other or future circumstance.

(d) This Agreement is for the sole and exclusive benefit of the Parties and shall not create a contractual relationship with, or cause of action in favor of, any third party.

(e) Neither Party shall have the right to voluntarily assign its interest in this Agreement, including its rights, duties, and obligations hereunder, without the prior written consent of the other Party, which consent may be withheld by the other Party in its sole and absolute discretion. Any assignment made in violation of the terms of this Section 8(e) shall be null and void and shall have no force and effect.

(f) In the event that any provision of this Agreement is determined to be invalid or unenforceable for any reason, in whole or part, the remaining provisions of this Agreement shall be unaffected thereby and shall remain in full force and effect to the fullest extent permitted by law, and such invalid or unenforceable provision shall be replaced by the Parties with a provision that is valid and enforceable and that comes closest to expressing the Parties' intention with respect to such invalid or unenforceable provision.

(g) Whenever this Agreement requires or provides that (i) a notice be given by a Party to the other Party or (ii) a Party's action requires the approval or consent of the other Party, such notice, consent or approval shall be given in writing and shall be given by personal delivery, by recognized overnight courier service, email or by certified mail (return receipt requested), postage prepaid, to the recipient thereof at the address given for such Party as set forth below, or to such other address as may be designated by notice given by any Party to the other Party in accordance with the provisions of this Section 8(g):

If to Bonneville:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attention: Steve Kerns, Director Grid Modernization and EIM
E-mail: srkerns@bpa.gov

If to the ISO:

California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Attention: Petar Ristanovic, Vice President, Technology
E-mail:PRistanovic@caiso.com

Each notice, consent or approval shall be conclusively deemed to have been given (i) on the day of the actual delivery thereof, if given by personal delivery, email sent by 5:00 p.m., or overnight delivery, or (ii) date of delivery shown on the receipt, if given by certified mail (return receipt requested). It is the responsibility of each Party to provide, in accordance with this Section, notice to the other Party of any necessary change in the contact or address information herein.

(h) This Agreement may be executed in one or more counterparts (including by facsimile or a scanned image), each of which when so executed shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

(i) Nothing contained in this Agreement shall be construed as creating a corporation, company, partnership, association, joint venture or other entity with the other Party, nor shall anything contained in this Agreement be construed as creating or requiring any fiduciary relationship between the Parties. No Party shall be responsible hereunder for the acts or omissions of the other Party.

(j) The decision to execute an EIM service agreement and participate in the EIM remains within the sole discretion of Bonneville and the decision whether to continue to offer EIM services (subject to Sections 1(c) and 2) remains within the sole discretion of the ISO.

(k) Nothing in this Agreement shall preclude a Party from exercising any rights or taking any action (or having its affiliates take any action) with respect to any other project.

(l) Unless otherwise expressly provided, for purposes of this Agreement, the following rules of interpretation shall apply: (i) any reference in this Agreement to gender includes all genders, and the meaning of defined terms applies to both the singular and the plural of those terms; (ii) the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this Agreement; (iii) all references in this Agreement to any "Section" are to the corresponding Section of this Agreement unless otherwise specified; (iv) words such as "herein," "hereinafter," "hereof," and "hereunder" refer to this Agreement (including Exhibit A to this Agreement) as a whole and not merely to a subdivision in which such words appear, unless the context otherwise requires; (v) the word "including" or any variation thereof means "including, without limitation" and does not limit any general statement that it follows to the specific or similar items or matters immediately following it; and (vi) the Parties have participated jointly in the negotiation and drafting of this Agreement and, in the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as jointly drafted by the Parties and no presumption or burden of proof favoring or disfavoring any Party will exist or arise by virtue of the authorship of any provision of this Agreement.

9. Governing Law; Venue. This Agreement shall be governed by, and construed and interpreted in accordance with, federal law. Venue for any action hereunder shall be FERC, where subject to its jurisdiction, or otherwise any federal court with jurisdiction.

10. Communication. The Parties shall develop a communication protocol for the dissemination of material information associated with the Project, which shall be approved by Bonneville and the ISO.

11. Dispute Resolution. Unless otherwise provided herein, each of the provisions of this Agreement shall be enforceable independently of any other provision of this Agreement and independent of any other claim or cause of action. In the event of any dispute arising under this Agreement, the Parties shall, to the extent practicable, first attempt to resolve the matter through direct good faith negotiation between the Parties, including a full opportunity for escalation to executive management within the Parties' respective organizations. If the Parties are unable to resolve the issue within thirty (30) calendar days after such escalation of the dispute, then for matters subject to FERC jurisdiction either Party shall have the right to file a complaint under Section 206 of the Federal Power Act. For all other matters, the Parties may pursue litigation in a federal court with jurisdiction over the Parties.

12. Third Party Agreements. The Parties may engage in discussions with third parties, either jointly or unilaterally, to facilitate the Project. Each Party may adopt or modify tariffs or enter into or modify binding agreements between such Party and third

parties to implement the approved terms and conditions of the Project or EIM as necessary and appropriate.

13. Compliance.

(a) Each Party shall comply with all applicable federal, state, local or municipal governmental authority; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC, WECC; or any court or governmental tribunal, having jurisdiction over the Party in connection with the execution, delivery and performance of its obligations under this Agreement.

(b) This Agreement is not intended to modify, change or otherwise amend the Parties' current functional responsibilities associated with compliance with WECC and NERC Reliability Standards; provided, however, the Parties may enter into separate mutually agreed to arrangements to clarify roles and responsibilities associated with compliance with WECC and NERC Reliability Standards in respect of this Agreement.

14. Bonneville's EIM Implementation and Participation Principles. The Parties recognize the following principles regarding implementation of the Project and Bonneville's potential participation in the EIM.

(a) Statutory, Regulatory, and Contractual Requirements. Bonneville's EIM implementation and participation will be consistent with its statutory, regulatory, and contractual requirements.

(b) Voluntary Market Participation. Bonneville's EIM participation will include voluntary market entry and exit, voluntary bid and offer volumes and pricing, voluntarily making transmission available for EIM Transfers and the ability to voluntarily forego engaging in EIM Transfers in one or more specified operating intervals consistent with the ISO tariff and the Bonneville Tariff.

(c) Reliability and Operation of the Federal Power and Transmission Systems. Bonneville will continue to be responsible for the reliable operation of the Federal Columbia River Power System and the Federal Columbia River Transmission System. Notwithstanding the ISO's resource sufficiency requirements for the EIM, Bonneville will retain the exclusive right to determine what is required to maintain reliability within its balancing authority area and on its transmission system. The Parties will work in good faith during implementation to ensure that Bonneville's EIM participation will not interfere with Bonneville's existing reliability tools.

(d) Federal Generation Participation. Bonneville may utilize the ISO's resource aggregation models to participate in the EIM as permitted by the

ISO's Business Practice Manuals. If Bonneville chooses to use an available resource aggregation model, Bonneville will identify its aggregated participating resources, aggregated non-participating resources, and other resources in the ISO's master file.

(e) Automation Support. In order to effectively participate in the EIM and ensure both reliable and economic outcomes, Bonneville will endeavor during implementation to automate interactions with existing EIM user interfaces based on the ISO's technical specifications. The ISO will assist Bonneville based on jointly determined requirements, feasibility and cost by 1) providing Application Programming Interfaces to interactions with existing EIM user interfaces, and 2) system or tool enhancements as jointly agreed.

(f) Greenhouse Gas Attributes. If Bonneville elects to allow its EIM transfers to be delivered to California, the transfers will be consistent with the Cap and Trade program administered by the California Air Resources Board, which may include Bonneville's status as an Asset Controlling Supplier.

(g) Base Schedule Submission Timeframes. Prior to the Implementation Date, the ISO will pursue, involving Bonneville and other stakeholders, moving the market closing timeline for financially binding hourly resource plans from T-40 to T-30. In addition, the ISO will explore with Bonneville and other stakeholders other potential enhancements to the EIM fifteen minute market timelines.

(h) Consideration of Other EIM Enhancements. Prior to the Implementation Date, Bonneville will propose in the appropriate ISO process(es) or forum(s), and the ISO will consider, certain EIM enhancements that:

i. improve the accuracy of hourly resource plans;

ii. permit resource sufficiency obligation transfers, *e.g.*, bid range transfers;

iii. improve the flexible ramping sufficiency test through various mechanisms, including but not limited to incorporation of renewable generation forecasts into the flexible ramping requirement computation; and

iiii. increase transparency of data required for the validation of EIM settlement statements.

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Implementation Agreement as of the date first above written.

BONNEVILLE POWER ADMINISTRATION

By: ______________________________

Name: Janet C. Herrin
Title: Chief Operating Officer

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

By: _____________________________

Name: Petar Ristanovic
Title: Vice President, Technology

EXHIBIT A: PROJECT SCOPE AND SCHEDULE

The Project consists of the activities and delivery dates identified in this Exhibit A, implemented in accordance with the Agreement. The Parties have included a schedule for the Implementation Date to coordinate their efforts required for completion of the Project on a milestone track.

The ISO shall invoice Bonneville for each of the milestones described below pursuant to section 4(c) of the Agreement.

The Parties understand that input received from stakeholders during the course of implementing the Project, conditions imposed or questions raised in the regulatory approval process, and the activities of the Parties in implementing the Project may cause the Parties to determine that changes in the Project are necessary or desirable. Accordingly, this Exhibit A may be modified in accordance with Section 3(c) of the Agreement.

Each Party is responsible for performing a variety of tasks necessary to achieve the milestones on the scheduled dates specified in the table below ("Timeframe") and shall plan accordingly. The Parties shall communicate and coordinate as provided in the Agreement to support the planning and execution to complete the Project.

Project Scope and Milestones	Timeframe
Milestone 1 – Effective Date. Upon the Effective Date of the Implementation Agreement as described in Section 1 of this Agreement.	September 2019 – December 2019
Milestone 2—Detailed Project Management Plan. The Parties will develop and initiate a project management plan that describes specific project tasks each Party must perform, delivery dates, project team members, meeting requirements, and a process for approving changes to support completion of the Project. This phase will include a detailed IT system review to assist Bonneville in development of a detailed metering plan, bidding and billing system(s), and coordination with Bonneville EMS upgrade(s). Work will be initiated on the Bonneville staff training program using the foundational and detailed system computer-based training modules, as well as on the resource data templates needed during Milestone 2.	October 2019- April 2020
Milestone 3— System Implementation and Connectivity Testing for Market Model. Upon ISO promotion of market network model including the Bonneville area to the non-production system, and allowing Bonneville to connect and exchange data in advance of market simulation.	May 2020- June 2021
Milestone 4— Market Simulation. Completion of day-in-life simulation, and start of market simulation scenarios.	June 2021- November 2021

Project Scope and Milestones	Timeframe
Milestone 5— Start of Parallel Operations. The ISO will activate a parallel operation environment to practice production grade systems integration as well as market processes and operating procedures in anticipation of the impending Bonneville activation as an EIM Entity and to confirm compliance with the EIM readiness criteria set forth in the ISO tariff. This milestone will include the following: • Staged Weekday/Weekend/Weeknight (in progressive sequence) operations with considerations of minimum support during holiday periods; and • Full 24/7 operations.	December 2021-February 2022
Milestone 6—System Deployment and Go Live no later than 3/2/2022. Implementing the Project and going live will include resource registration, operating procedures and updates, execution of service agreements, completion of the Bonneville tariff process, applicable board approvals, the filing and acceptance of service agreements and tariff changes with FERC, and completion and filing of a readiness criteria certification in accordance with the ISO tariff.	February 2022-March 2022

EXHIBIT B
FEDERAL GOVERNMENT CONTRACT PROVISIONS

This Exhibit B contains federal government contract provisions that are necessary for Bonneville to enter into the Agreement.

1. Covenant Against Contingent Fees

Each of the Parties warrants to each of the other Parties that no person or selling agency has been employed or retained by it to solicit or secure the Agreement upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by any Party for the purpose of securing business. For breach or violation of this warranty by any Party other than Bonneville, Bonneville will have the right to annul the contract without liability or in its discretion to deduct from the contract price or consideration the full amount of such commission, percentage, brokerage, or contingent fee.

2. Contract Work Hours and Safety Standards

The Agreement, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act (Act), 40 U.S.C. § 3701, as amended or supplemented, is subject to the provisions of the Act, 40 U.S.C. §§ 3701-3708, as amended or supplemented, and to regulations promulgated by the Secretary of Labor pursuant to the Act.

3. Equal Opportunity Employment Practices

Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Parties will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated herein by reference the same as if the specific language had been written into the contract.

4. Use of Convict Labor

The Parties agree not to employ any person undergoing sentence of imprisonment in performing the Agreement except as provided by 18 U.S.C. § 3622(c), as amended or supplemented, and Executive Order No. 11755, 39 Fed. Reg. 779 (1973), as amended or supplemented.