Bonneville Power Administration

Post-2028 Residential Exchange Program Comprehensive Plan

Traditional REP – Phase 2

Power Services
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1 Introduction

The Bonneville Power Administration (BPA) has prepared this comprehensive plan (REP Comprehensive Plan) to provide a framework and overview of the processes, scope of issues to be resolved, and schedule over the next two years regarding the future implementation of the Residential Exchange Program (REP). As described more fully below, the current implementation of the REP is the subject of a settlement agreement that expires on September 30, 2028. The Comprehensive Plan outlines the processes that BPA expects to engage in to prepare for REP implementation following expiration of the current settlement. This paper does not make any substantive decisions regarding REP implementation.

BPA has scheduled a hybrid workshop in the BPA Rates Hearing Room on **Monday, July 28, 2025, at 9:00am** (PDT) to discuss the timelines and processes addressed herein.[1] Workshop details can be found on BPA's Event Calendar. BPA is seeking stakeholder feedback on the timelines by **August 7, 2025**. Comments on the timelines may be submitted to the Post-2028 REP inbox: rep2028@bpa.gov.

2 Background and Context

Until the 1970s, BPA had low-cost hydroelectric resources sufficient to meet the projected demands of the region's three primary customer groups: public power customers, investor-owned utility (IOU) customers, and direct service industrial customers (DSIs)[2]. The public power customers are collectively called "preference customers" because they are afforded preferential rights to the sale of available Federal power.[3] Investor-owned utilities (IOUs) and direct service industrial customers (DSIs) in the Pacific Northwest are non-preference customer groups, meaning their access to Federal power comes only after the preferential rights of public power customers.

By the 1970s, projections showed that public customers would soon require all of BPA's power, thus limiting BPA's ability to sell to other customers.[4] BPA announced that firm power sales to IOUs would cease in 1973.[5] BPA also advised the DSIs that as their contracts expired during the 1981-1991 period, they were not likely to be renewed.[6] Cost disparities between the rates of public power end-use consumers and IOU end-use consumers heightened the stakes to gaining access to BPA's low-cost power as "consumers that lived in areas served by public utilities enjoyed much cheaper power than consumers served by IOUs."[7] In the face of this escalating competition

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[1] Meeting information is available here: https://www.bpa.gov/learn-and-participate/public-involvement-decisions/event-calendar/event-details?pageid=%7bAD38A0F6-678E-4E82-AC3F-AB0CFC6C206D%7d.

[2] The DSIs were large industrial customer that purchased power directly from BPA. These included aluminum plants, steel mills, wood and pulp production, and other large production loads.

[3] *See* 16 U.S.C. § 832c(a).

[4] *See* H.R. Rep. No. 976 Pt. I, 96th Cong., 2d Sess. 23-26 (1980).

[5] *See Aluminum Co. of America v. Central Lincoln PUD*, 467 U.S. 380, 385 (1984) (*Alcoa*).

[6] *Id.*

[7] *Id.* at 399.

for increasingly scarce resources, the Northwest was "poised for regional civil war--an interstate battle over the allocation of low-cost Federal power."[8]

In 1980, Congress enacted the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act or Act), 16 U.S.C. § 839, *et seq*., to provide a "comprehensive solution" to the impending power disputes.[9] By passing the Northwest Power Act, Congress sought to "avoid the prospect of unproductive and endless litigation" among BPA's customer groups by creating a legislative solution to the numerous issues.[10]

A key feature of the Northwest Power Act is section 5(c), which establishes a program colloquially called the Residential Exchange Program or REP.[11] Under the REP, residential and farm[12] consumers of higher-cost Pacific Northwest utilities (primarily IOUs) gain access to low-cost Federal power reserved by federal statute to public power customers. This access comes in the form of a power-neutral sale and exchange, where utilities with high-cost resources sell power to BPA at their average system cost of resources (ASC).[13] BPA, in turn, sells the same quantity of power back to the utilities at BPA's cost of power (the PF Exchange Rate), modified by certain rate adjustments. Historically and practically, this "exchange" of power has been implemented as a financial transaction. BPA pays the utility the net difference between the two sales (ASC-PF Exchange Rate), multiplied by the utility's qualifying residential and farm load (exchange load). The Act mandates that the "cost benefits" of this exchange be passed on by the utilities to their retail residential and farm consumers, typically as a credit on their power bill.[14] In this way, "the exchange program is designed to provide rate relief for consumers served by IOUs."[15]

The cost of the REP is recovered in BPA's power rates, primarily its PF rate, which is paid by BPA's public customers.[16] Public customers are protected from some costs of the REP through a rate test provision in section 7(b)(2) of the Northwest Power Act.[17] The 7(b)(2) rate test requires BPA to test its proposed PF rate against a hypothetical rate adjusted for certain assumptions, one of which is to assume no REP purchases or sales occur.[18]

Presently, eight regional utilities participate in the REP: six IOUs and two publicly-owned utilities (Public customer), under implementation provisions of the 2012 REP Settlement Agreement

[8] *Pacific Northwest Electric Power Supply and Conservation: Hearings on H.R. 9020, H.R.9664, and H.R. 5862 Before the Subcomm. on Water and Power Resources of the House Comm. on Interior and Insular Affairs, 95th Cong., 1st Sess*. Pt. I, 133 (Dec. 5, 1977) (Statement of Dixy Lee Ray, Governor of Washington).
[9] *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1107 (9th Cir. 1984).
[10] *Alcoa*, 467 U.S. at 386.
[11] *See* 16 U.S.C. § 839c(c)(1).
[12] Eligible farm load is limited to the first 400 horsepower, (222,000 kWh), of irrigation and pumping during any monthly billing period. *See* 16 U.S.C. § 839a(18).
[13] 16 U.S.C. § 839c(c)(1).
[14] 16 U.S.C. § 839c(c)(3).
[15] *Alcoa*, 467 U.S. at 399.
[16] *See* 16 U.S.C. § 839e(b)(1). The costs of the REP are also allocated to BPA's other rates, including the Industrial Firm Power rate (IP) and New Resource (NR) rate. Sales under these rates have in recent years been small, leaving the PF rate as the primary source for recovering these costs.
[17] *See* 16 U.S.C. § 839e(b)(2).
[18] *Id.* at §§ 839e(b)(2)(A)-(E).

which expires September 30, 2028. BPA and regional stakeholders are engaged in deliberative efforts to determine implementation of the REP for the post-2028 period (BP-29).

The REP has been a valuable, albeit contentious, component of BPA's statutory obligations. It is one of the few programs BPA implements that impacts every consumer in the region. Every retail residential and farm consumer in the region served by an IOU has, at some point, received on their monthly retail bill a rate credit from BPA for the REP. While for each utility this amount will vary, today the credit reduces consumers' bills by around 5%. For every Public customer in the region, the REP represents a cost in their BPA wholesale power rate, and ultimately, a cost to their retail consumers. By the end of the current settlement (which expires on September 30, 2028), BPA will have paid over $11 billion to regional utilities in REP payments under section 5(c) (*i.e.,* 1981-2028).

2.1 REP Implementation History

From 1981-1985, the Northwest Power Act required that the REP be paid entirely by BPA's direct service industrial (DSI) customers, which at the time accounted for approximately 30 percent of BPA's load.[19] Beginning in 1985, however, the costs of the REP would be recovered from other rates – including the PF rate charged public power customers– subject to the rate test described in section 7(b)(2). Since 1985, the REP has created an inherent tension between the primary recipients of REP benefits (IOUs and their consumers) and the primary payers of the REP benefits (preference customers and their consumers). The first 20 years of implementation of the REP (1980-2000) saw multiple disputes over BPA's implementation of the Average System Cost (ASC) Methodology.[20] In the late 1990s, BPA and IOU REP participants attempted to avoid continued litigation by settling the REP. This approach led to the 2000 REP settlement. The 2000 REP settlement offered power and monetary payments to IOUs in return for a waiver of claims and their participation in the REP. BPA classified the costs of the 2000 REP settlement as a "settlement cost" and allocated these costs to public customers under section 7(g) of the Northwest Power Act in the WP-02 rate proceeding (FY 2002-2006). Notably, BPA did not perform the section 7(b)(2) rate test when deciding to enter into the 2000 REP Settlement or recovering its costs in the WP-02 rate case.

Public customers challenged the 2000 REP Settlement and the WP-02 rates in the Ninth Circuit Court of Appeals, arguing that BPA could not use its contracting authority to circumvent the protections afforded to public customers by, among other provisions, the section 7(b)(2) rate test. In May 2007, the Ninth Circuit granted the petitions, remanded BPA's WP-02 rates and overturned

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[19] *See* 16 U.S.C. § 839e(c)(1)(A). The DSI load in this period was around 3,300aMW. As of this writing, BPA serves only a single DSI, and its load is around 12aMW.

[20] Parties first challenged the development and terms of the ASC Methodology, *see Pub. Util. Comm'n of Or. v. Bonneville Power Admin.,* 767 F.2d 622 (9th Cir. 1985)*; Pac. Power & Light v. Bonneville Power Admin*., 795 F.2d 810 (9th Cir. 1986), *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986). Later, parties challenged BPA's implementation of the ASC Methodology, *see Wash. Util. & Transp. Comm'n v. FERC*, 26 F.3d 935 (9th Cir. 1994); *CP Nat. Corp. v. Bonneville Power Admin*., 928 F.2d 905 (9th Cir. 1991).

the 2000 REP Settlements.[21] By the time the Court had ruled, BPA had already paid out close to $2.1 billion in settlement payments to the IOUs. The IOUs, in turn, had distributed these funds to their residential and farm consumers. Following the Court's remand, BPA ended the settlement payments to the IOUs and commenced a supplemental rate proceeding (WP-07 Supplemental rate case) to reinstate the traditional implementation of the REP, perform the section 7(b)(2) rate test, and determine refunds for any overpayments of REP benefits to the IOUs for the FY 2002-2007 period. BPA also commenced separate processes to develop new contracts to implement the REP (called Residential Purchase and Sales Agreements (RPSA)) and revised the methodology BPA used to determine a utility's ASC, called the ASC Methodology or ASCM. In the WP-07 Supplemental rate case, BPA concluded that it had overpaid the IOUs by about $1 billion and proposed to recover this amount from IOUs by offsetting future REP payments. BPA explained its decision in the 706-page, WP-07 Supplemental Record of Decision (WP-07 Supplemental ROD).[22] IOUs, Public customers, and many other interested parties challenged BPA's REP decisions in the WP-07 Supplemental ROD and related decisions, with the result that at one point 56 petitions for review were pending before the Ninth Circuit in four consolidated cases.[23]

2.2 2012 REP Settlement

The prospect of endless litigation over the REP led many representatives of public customers and IOUs to participate in mediation of the REP disputes. In 2011, a proposed settlement (2012 REP Settlement) was reached between public and IOU representatives that would settle the total aggregate amount of REP payments to IOU participants until 2028, while also providing refunds for Public customers to account for past overpayments. To ensure the 2012 REP Settlement would withstand judicial scrutiny, BPA evaluated the 2012 REP Settlement in a section 7(i) proceeding. In particular, BPA evaluated whether the net-present value of the fixed payments in the 2012 REP Settlement would provide greater (or fewer) REP payments to the IOUs than under the traditional statutory formula. To test this assumption, BPA calculated REP payments under 26 scenarios. These scenarios considered the impact on REP payments of potential future market and resource risks as well as the effect of issues in litigation. All told, BPA found that under the vast majority of scenarios, the 2012 REP Settlement provided fewer REP benefits to the IOUs, and greater cost protection to Public customers, than would otherwise have occurred under the traditional implementation of the REP. BPA explained its analysis and its decision to adopt the proposal in the 2012 REP Settlement in the final REP-12 Record of Decision (REP-12 ROD).[24]

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[21] *See Portland Gen. Elec. Co., v. Bonneville Power Admin.,* 501 F.3d 1009 (9th Cir. 2007) (holding 2000 REP Settlements unlawful); *Golden NW Alum. v. Bonneville Power Admin.,* 501 F.3d 1037 (9th Cir. 2007) (remanding BPA's WP-02 rates).

[22] *See* 2007 Supplemental Wholesale Power Rate Case, Administrator's Final Record of Decision, WP-07-A-05, (Sept. 2008) (WP-07 Supplemental ROD). The WP-07 Supplemental ROD is available on BPA's Record of Decision website, under 2008 decisions. *See* https://www.bpa.gov/learn-and-participate/public-involvement-decisions/record-of-decisions.

[23] For a complete description of these events, please see Residential Exchange Program Settlement Agreement Proceeding (REP-12), Administrator's Final Record of Decision, REP-12-A-02, at 344-48 (July, 2011) (hereafter REP-12 ROD). The REP-12 ROD is available on BPA's Record of Decision website, under 2011 decisions. *See* https://www.bpa.gov/learn-and-participate/public-involvement-decisions/record-of-decisions.

[24] *See id.*

A single challenge was made to the REP-12 ROD and 2012 REP Settlement in the Ninth Circuit Court of Appeals. In 2013, the Court affirmed the Administrator's decision to adopt 2012 REP Settlement and the REP-12 Record of Decision.[25]

The 2012 REP Settlement has provided unparalleled stability and certainty during its term. The past 14 years of REP implementation have seen no legal disputes regarding the REP implementation, ASCs, or REP payments. End-use consumers throughout the Pacific Northwest region have benefitted from this period of collaboration and certainty. When the 2012 REP Settlement expires in September 2028, regional residential and farm consumers will have received over $4 billion in REP payments for rate relief through the settlement.

The ending of the 2012 REP Settlement in September 2028 also ends the pause on disputes over BPA's implementation of the REP. The 2012 REP settlement did not resolve the "knotty legal and factual questions regarding the section 7(b)(2) rate test . . . that have plagued BPA's rate proceedings."[26] Instead, BPA "withdrew" its decisions regarding the REP from the WP-07 Supplemental ROD and replaced those decisions with the outcome provided in the 2012 REP Settlement and accompanying REP-12 ROD.[27] To that end, the 2012 REP Settlement expressly reserved all parties' rights and positions.[28] In regard to BPA's implementation of the section 7(b)(2) rate test, BPA further committed in the 2012 REP Settlement to "conduct a proceeding and issue a record of decision to determine, for the period starting with Fiscal Year 2029, whether, and if so, how, to modify or replace its legal interpretation of, and methodology for implementing, sections 7(b)(2) and 7(b)(3)" of the Northwest Power Act.[29] With the expiration of the 2012 REP Settlement drawing near, BPA must prepare for the post-2028 REP implementation.

2.3 Provider of Choice Concept Paper Phases: REP Settlement Phase and Traditional REP Phase

In July 2022, BPA issued its Provider of Choice Concept paper in which BPA "officially launche[d] its policy development process" to describe and define the principles, goals, policies, and components of its post-2028 power sales contracts.[30] Relevant here, the Provider of Choice Concept Paper also described a two-phase approach for developing the post-2028 implementation of the REP. Specifically, BPA proposed "(1) a regional settlement phase; and (if the settlement phase is unsuccessful), (2) an REP traditional preparation phase."[31]

[25] *Assoc. of Pub. Ag. Customer v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013).
[26] REP-12 ROD at 29.
[27] REP-12 ROD at 29 ("This alternative, embodied in the terms of the Settlement, would replace BPA's decisions in the WP-07 Supplemental ROD and WP-10 ROD, which have been hotly contested by all parties, with the agreed-upon value established by the Settlement and signed by all of the region's IOUs, three public utility commissions, and 88 percent of BPA's [Public] customers (by load).")
[28] *See* REP-12 ROD, Appendix A, 2012 REP Settlement Agreement, § 11 (hereafter "2012 REP Settlement").
[29] 2012 REP Settlement, § 11.3.
[30] Bonneville Power Administration, Provider of Choice Concept Paper, July 2022, at 1, ("PoC Concept Paper") *available at* https://www.bpa.gov/-/media/Aep/power/provider-of-choice/bpa-provider-of-choice-concept-paper-final-july-2022.pdf.
[31] PoC Concept Paper at 59.

The REP Settlement Phase, as its name implies, was a period of time set aside to focus BPA efforts to "facilitate and encourage regional discussions towards a structured settlement of the REP[.]"[32] BPA tentatively designed the REP Settlement phase to run from September 2022 through around September 2025. This phase "builds on the foundation established by the 2012 REP Settlement."[33] The 2012 REP Settlement took almost 4 years of constant work and negotiation to achieve. In view of this experience, BPA set aside multiple years for the REP Settlement Phase to permit regional parties time to work toward a negotiated settlement. To provide structure to these discussions, BPA further broke this phase into a number of distinct sub-phases: (1) the REP Dry Run and Preparation phase; (2) REP Contract Negotiation phase; and (3) an REP Settlement Evaluation Process and Decision phase.[34]

Because settlement was not guaranteed, BPA also described a second phase of REP preparation in the Provider of Choice Concept Paper– the traditional REP preparation phase.[35] The REP traditional preparation phase would begin the earlier of the end of settlement negotiations or the summer of 2025.[36] During the traditional REP preparation phase, BPA would shift its focus from facilitating and supporting settlement discussions to preparing its positions and policies for a traditional REP implementation. A collection of processes, policies, contracts, and proceedings would need to be completed to ensure that BPA had the necessary components of the REP developed and ready for the post-2028 BP-29 implementation of the REP.[37]

2.4 REP Settlement Phase (Phase 1)

The REP Dry Run and Preparation Sub-Phase commenced in late summer 2022.[38] This phase began with general education workshops on the REP, its implementation, and an overview of the areas of dispute.[39] Following these discussions, BPA prepared "dry run" calculations of REP benefits using data from the BP-22 rate period as inputs. BPA ran numerous scenarios based on various assumptions on key REP issues (*e.g.,* implementation of section 7(b)(2)) from IOU and Public customer positions reflected in the REP-12 ROD and administrative record).[40] BPA also ran scenarios based on current IOU and Public customers providing their current "best case" scenario assumptions. These dry runs provided "a working educational model from which regional

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[32] *Id*.
[33] PoC Concept Paper at 59.
[34] PoC Concept Paper at 59-60.
[35] PoC Concept Paper at 60.
[36] PoC Concept Paper at 61.
[37] PoC Concept Paper at 61.
[38] *See* Letter To Customers interested in Post-2028 Residential Exchange Program, August 23, 2022, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2022_08-REP-letter-to-the-region.pdf.
[39] *See* Post-2028 Residential Exchange Program Workshop, Sept. 27, 2022, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/092722-Post-2028-REP-Phase-1-Kickoff-WorkshopV4.pdf; *See also* Post-2028 Residential Exchange Program Workshop, October 25, 2022, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/102522-Post-2028-REP-Phase-1-Second-Workshop.pdf.
[40] *See* Post-2028 Residential Exchange Program Workshop, February 21, 2023, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/022123-post-2028-rep-sub-phase-1-fourth-workshop.pdf.

stakeholders may be able to familiarize themselves with, and get a sense of scale for, the various assumptions and factors that affect REP benefits levels."[41] In particular, the dry run phase would help "orient parties to the outstanding issues regarding the REP implementation, consider which scenarios to pursue, which to abandon, and identify any new scenarios not previously considered."[42] Through the dry run analysis, BPA anticipated collecting the "main scenarios" list from which to build its evaluation data set. BPA completed its dry run analysis and the identification of its primary scenarios on May 23, 2023.[43]

Following the dry run phase, BPA prepared scenario analysis for the REP Contract Negotiation sub-phase. This phase began with public workshops where both Public customers and IOUs prepared settlement principles and perspectives on the REP.[44] On September 21, 2023, BPA issued a letter to the region, noting that further BPA-sponsored workshops on REP negotiations would not be scheduled.[45] In the letter, BPA encouraged IOU and Public representatives to continue to meet in private discussions. Additionally, BPA noted that it would hold a workshop in January 2024 with the results of its scenario analysis using data from the BP-24 rate case for the main scenarios developed from the Dry Run and Preparation Sub-Phase. These results were presented at a public workshop on January 23, 2024.[46]

Discussion between Public and IOU representatives continued throughout 2024. During the discussions, representatives from both Public and IOU interest groups informed BPA of the status of negotiations. These interactions have provided important context and established a working dialogue among the parties. However, it is BPA's understanding that future negotiations over a REP settlement do not appear likely at this time. BPA appreciates the time and dedication Publics and IOUs dedicated to these efforts and BPA encourages them to continue their dialogue to find a viable, long-term solution to the REP. BPA stands ready to assist the parties as needed. In the meantime, BPA must pause its efforts on scenario analysis and settlement analytics to prepare for implementing the traditional REP for the BP-29 rate period (FY 2029) and beyond.

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[41] PoC Concept Paper at 59.

[42] PoC Concept Paper at 60.

[43] *See* Post-2028 Residential Exchange Program Workshop, May 23, 2023, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/052323-pst-2028-rep-sub-phase-1-sixth-workshop.pdf.

[44] *See* Post-2028 Residential Exchange Program Workshop, June 27, 2023, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/20230627-post-2028-rep-sub-phase-1-customer-workshop.pdf.

[45] *See* Letter to Regional Stakeholders Participating in the Post-2028 Residential Exchange Program Process, September 21, 2023, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20230921-residential-exchange-letter-to-the-region.pdf.

[46] *See* Post-2028 Residential Exchange Program Workshop, January 23, 2024, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/012324-Post-2028-REP-Customer-Workshop-Updated-01242024.pdf.

3 Traditional REP - Phase 2

3.1 Introduction

This section of the REP Comprehensive Plan describes the various processes, policies, methodologies, and contracts that must be developed and active prior to October 1, 2028, in order implement the traditional REP in the post-2028 period.

3.2 Overview of Components of Traditional REP

Section 5(c)(1) provides that

> Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.[47]

The amount of power sold under the exchange is equal to the "residential load" of the utility.[48] In effect, under section 5(c), an exchanging utility may sell an amount of power equal to that utility's residential load at "the average system cost of that utility's resources." BPA buys this power, then in exchange, sells back the same amount of power at BPA's cost of power as described in section 7 of the Northwest Power Act.[49] The two power transactions offset each other and result in a net dollar amount. Section 5(c)(3) describes what is to be done with the resulting net dollar benefit if it is in the utility's favor: the "cost benefit" of the exchange must be "passed through directly to such utility's residential loads within such state."[50]

Because the REP is designed to be net power neutral, the REP has historically been implemented as a "paper transaction" that results in a payment to the REP participants.[51] To that end, BPA has used the below formula to calculate the exchanging utility's payments under the REP:

> **(Exchanging Utility's Average System Cost (ASC) – BPA's Priority Firm (PF) Exchange Rate) x Exchanging Utility's Residential and Farm Load = REP benefits.**[52]

Each component of this calculation is informed by statutory provisions.

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[47] 16 U.S.C. § 839c(c)(1).
[48] 16 U.S.C. § 839c(c)(2).
[49] *See* 16 U.S.C. § 839e(b)(1)-(2).
[50] 16 U.S.C. § 839c(c)(3).
[51] *See PacifiCorp v. FERC,* 795 F.2d 816, 818 (9th Cir. 1986); *see also Pub. Util Comm'n of Or. v. Bonneville Power Admin.,* 767 F.2d 622, 624-25 (9th Cir. 1985) (describing exchange as a "bookkeeping entr[y]"), *Pac. Power and Light Co., v. Bonneville Power Administration*, 795 F.2d 810, 812 (9th Cir. 1986) ("accounting transaction").
[52] *See Assoc. of Pub. Agency Customers v. Bonneville Power Admin.,* 733 F.3d 939, 945-46 (9th Cir. 2013) (describing this formula as "the traditional formula for deciding if an IOU is entitled to a 'REP Benefit'. . .")

3.2.1 Exchanging Utility's Average System Cost (ASC)

The ASC is the cost of an exchanging utility's resources. Section 5(c)(7) of the Northwest Power Act provides that BPA will determine utilities' ASCs on the basis of a methodology developed by BPA in consultation with certain parties in the Pacific Northwest region.[53] The **ASC Methodology** is subject to review and approval by the Federal Energy Regulatory Commission (Commission or FERC).[54]

Section 5(c) of the Northwest Power Act provides BPA wide latitude to determine the ASC Methodology in consultation with the Northwest Power Planning and Conservation Council, BPA customers, and state regulatory bodies.[55] BPA has developed three ASC methodologies over the last 40 years.[56] BPA's most current ASC Methodology was developed in 2008 (2008 ASC Methodology) and approved by FERC in September of 2009.[57] ASC calculations under the current settlement agreements are determined by the 2008 ASC Methodology.

3.2.2 Priority Firm Exchange Rate

The PF Exchange rate is the rate at which BPA sells power to utilities participating in the section 5(c) exchange sale.[58] This rate reflects BPA's cost of power, modified by certain rate adjustments as provided for in sections 7(b)(1), 7(b)(2) and 7(b)(3) of the Northwest Power Act.[59] Under section 7(b), the PF Exchange rate begins at the same level as the PF rate charged to Public customers.[60] Section 7(b)(2) then directs BPA to perform a statutory rate test, known as the Section 7(b)(2) rate test, to determine whether the preference customer rate must be protected from certain costs created by the Northwest Power Act (including the REP).[61] To assist in its interpretation of the section 7(b)(2) rate test, BPA has historically developed both a **7(b)(2) legal interpretation** and **7(b)(2) implementation methodology**.[62] The last legal interpretation and

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[53] 16 U.S.C. § 839c(c)(7).

[54] *Id.*

[55] *See PacifiCorp v. FERC,* 795 F.2d 816, 818 (9th Cir. 1986) (noting that "neither the language of the statute nor the legislative history supports a holding that discretion to exclude costs is narrowly defined.") *See also Methodology for Sales of Electric Power to the Bonneville Power Admin*., 30 FERC ¶ 61,108, at 61,197 (Feb. 1, 1985) ("While the NPA requires establishment of an ascertainable methodology for determining the 'average system cost of a utility's resources', it provides no specific standards other than the three specific exclusions in NPA section 5(c)(7). This indicates that the Administrator's discretion was intended to be quite broad, which is consistent with the fact that the Administrator is implementing a new, complex and largely untested program that involves a sensitive balancing of several economic interests.")

[56] *See Sales of Electric Power to Bonneville Power Administration, Methodology and Filing Requirements*, 48 Fed. Reg. 46,970 (Oct. 17, 1983) (1981 ASCM); *Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293 (Oct. 5, 1984) (1984 ASCM); *Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology*, 74 Fed. Reg. 47,052 (Sep. 9, 2009) (2008 ASCM).

[57] *See Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology*, 128 FERC ¶ 61,222 (Sept. 4, 2009).

[58] *See* 16 U.S.C § 839c(a) (noting that "[s]uch sales shall be at rates established pursuant to section 839e of this title.")

[59] *See* 16 U.S.C. §§ 839e(b)(1)-(4).

[60] 16 U.S.C. § 839e(b)(1).

[61] 16 U.S.C. § 839e(b)(2).

[62] *See e.g.,* 1984 Section 7(b)(2) Legal Interpretation, May 31, 1984, *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1984-rod/rod-19840531-legal-interpretation-of-section-

methodology were developed in 2008[63], but both were subsequently withdrawn after the regional settlement on the REP was reached.[64]

3.2.3 Residential / Farm Load

Section 3(18) of the Northwest Power Act describes the type of load that is exchangeable under the REP.[65] It includes "usual" residential and farm loads and irrigation pumping loads up to 400 horsepower (222,000 kWh per month). The benefits of the REP must be passed through directly to these users.[66]

3.2.4 Other Impacts to Residential Exchange Program Benefits – In Lieu

The above components comprise the primary elements used in determining REP benefits for exchanging utilities. The Northwest Power Act also includes one discretionary feature for reducing the costs of the REP. Section 5(c)(5) provides that, in lieu of BPA purchasing power from an exchanging utility, BPA may purchase power from "other sources" if that other source is cheaper than the exchanging utility's ASC.[67] The power purchased from that other source would then be sold to the exchanging utility at the PF Exchange rate, thereby reducing that utility's benefit payments under the REP. This feature of the REP, which is discretionary, permits the Administrator to reduce the cost of the REP for a utility with a high ASC.[68]

3.3 Post-2028 REP Process Overview

The 2012 REP Settlement and related agreements allowed BPA to implement the REP consistent with its statutory authorities without addressing specific statutory questions on, among other parts, section 5(c) or section 7(b) of the Northwest Power Act.[69] With the expiration of the 2012 REP Settlement in September 2028, BPA must have policies, methodologies, and contracts in place in order to implement the REP for the post-2028 period. Three documents are essential for enabling BPA to implement the traditional REP: (1) the Residential Purchase and Sale Agreement (RPSA); (2) ASC Methodology; and (3) the section 7(b)(2) Methodology/Legal Interpretation.

7b2.pdf; 1984 Section 7(b)(2) Implementation Methodology, Aug. 17, 1984, *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1984-rod/rod-19840817-section-7b2-implementation-methodology.pdf.

[63] *See* Section 7(b)(2) of the NWPA Legal Interpretation, WP-07-A-06, Sept. 2008, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2008-BPAs-Legal-Interpretation-of-Section-7b2-of-the-NW-Power-Act.pdf; Section 7(b)(2) of the NWPA Implementation Methodology, WP-07-A-07, Sept. 2008, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/Extract-of-BPAs-Implementation-Methodology-2008.pdf.

[64] *See* REP-12 ROD, at 344-48.

[65] 16 U.S.C. § 839a(18).

[66] 16 U.S.C. § 839c(c)(3).

[67] 16 U.S.C. § 839c(c)(5).

[68] *See Assoc. of Pub. Agency Customer v. Bonneville Power Admin*., 733 F.3d 939, 960-61 (9th Cir. 2013).

[69] *See* REP-12 ROD at 29 (noting that the "Settlement is not intended to answer all of the knotty legal and factual questions regarding the section 7(b)(2) rate test and BPA's Lookback construct that have plagued BPA's rate proceedings . . ." and "the settling [Publics], IOUs, state commissions, and others have crafted the Settlement such that its focus is on reaching a reasonable resolution of the myriad conflicts in an equitable and timely manner without addressing individual claims. . ."); *see also* 2012 REP Settlement § 11 (preserving rights and making no admissions and waiving no claims).

Development of each of these documents will involve an administrative process with public participation and opportunities for comment.

3.4 Residential Purchase and Sale Agreement Process

3.4.1 Overview

The Residential Purchase and Sale Agreement (RPSA) is the contractual agreement between BPA and the exchanging utility that contains the terms and conditions for implementing the purchase and sale called for in section 5(c)(1) of the Northwest Power Act. In addition, it contains provisions to implement the requirement in section 5(c)(3) that the "cost benefits" of the REP be "passed through" to residential and farm consumers of participating utilities. The RPSA also contains certain statutory terms relating to displacing the exchange (*in lieu*) and terminating the exchange.

BPA has developed three versions of the RPSA over the past 40 years: 1981, 2000, and 2008. Additionally, in 2011, BPA developed a special form of the RPSA used in implementing the 2012 REP Settlement, called a Residential Purchase and Sale Implementation Agreement (RPSIA). The primary features and components of the RPSA and, as applicable, RPSIA, are described below.

3.4.2 Purchase and Sale Provisions

Section 5(c)(1) contemplates that both the exchanging utility and BPA make corresponding and offsetting sales and purchases to each other of equal amounts of power. The only difference between the sales is the price of the power sold. To reflect this aspect of the REP, the RPSAs have been structured as "bookkeeping" or "accounting" transactions.[70] Under this view, the utility does not deliver physical power to BPA to effectuate the exchange sale, and BPA does not return an equal amount of physical power to the exchanging utility to make an REP payment. The two power sales are netted out, and BPA pays the utility the difference between the utility's ASC and BPA's PF Exchange rate, multiplied by the utility's exchange load. The RPSAs have used varying terms to reflect this treatment.[71]

For the post-2028 REP implementation, BPA will need to determine whether this historic treatment should continue. BPA is aware that some utilities participating in the REP have requested implementing the section 5(c)(1) exchange as a physical sale and return of power between the utility and BPA. Additionally, BPA is informed that some utilities request that certain unidentified non-cost benefits should be provided as part of the purchase and sale exchange. BPA will evaluate and decide these issues in the RPSA development process.

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[70] *See PacifiCorp v. FERC,* 795 F.2d 816, 818 (9th Cir. 1986); *see also Pub. Util Comm'n of Or. v. Bonneville Power Admin.,* 767 F.2d 622, 624-25 (9th Cir. 1985) (describing exchange as a "bookkeeping entr[y]"), *Pac. Power and Light Co., v. Bonneville Power Administration*, 795 F.2d 810, 812 (9th Cir. 1986) ("accounting transaction").

[71] *See* 1980 RPSA, § 5 (deliveries "deemed" to be made to utility's Residential Load); 2000 RPSA, § 4 (noting the "purchase and sale transactions . . . are for the purpose of determining monetary benefits, if any, to be paid by BPA to [customer]."); 2008 RPSA, § 8 (describing an "accounting invoice" for the difference between exchanging utility and BPA sales).

3.4.3 Pass Through and Audit Provisions

Section 5(c)(3) requires that the "cost benefit" of the purchase and sale of the exchange in section 5(c)(1) be passed through to residential and farm consumers. This term requires that all benefits of the REP be distributed to retail consumers, and that the administering utility (and its shareholders) retain none of these benefits. The terms of this pass through are required to be "specified" in the contracts with the Administrator.[72]

The current Residential Exchange Program Settlement Implementation Agreement (REPSIA) contains provisions that require this pass through to occur under the terms of the 2012 REP Settlement. These terms will likely start as the foundation for similar "pass through" provisions in the new RPSAs. Additionally, since the 2008 RPSA, BPA has included audit procedures in the RPSAs that (1) ensure that only eligible loads are receiving REP payments; and (2) that the utility has controls and distribution practices in place that can demonstrate that the payments from the REP are reaching appropriate end-use consumers. Similar audit procedures will likely be included in the new RPSAs.

3.4.4 Termination, Suspension, and Deeming Provisions

The purchase and sale described in section 5(c)(1) was designed to compare wholesale power costs between participating utilities and BPA to mitigate the retail-rate disparity between residential and farm consumers of IOUs and Public utilities. As noted earlier, the formula BPA has used to calculate this cost benefit is: (ASC-PF Exchange) x Residential Load. In most instances, this formula results in a positive payment to the exchanging utility. That, however, is not always the case. If BPA's PF Exchange rate is *above* the utility's ASC, the exchanging utility would end up paying BPA. Historically, three options have been made available in the RPSA to address this situation.

<u>Statutory Termination Right</u>

Congress understood that the purchase and sale in the REP sales could result in the utility paying BPA under certain circumstances. As such, Congress allowed the utility to terminate its participation through section 5(c)(4) of the Northwest Power Act.[73] Section 5(c)(4) provides that if an exchanging utility's ASC falls below BPA's PF Exchange rate *because of* the section 7(b)(2) rate test (which results in an application of a supplemental charge imposed by section 7(b)(3)), the utility may "terminate" its participation in the REP "upon reasonable terms and conditions agreed to by the Administrator and such utility prior to such termination."[74] In this instance, the purchase and sale between BPA and the utility would end. The ability of the utility to re-enter the REP after exercising this termination would depend upon the terms of the RPSA.[75]

[72] 16 U.S.C. § 839c(c)(3).
[73] 16 U.S.C. § 839c(c)(4).
[74] 16 U.S.C. § 839c(c)(4).
[75] *See* Senate Report (Senate Comm. On Energy and Natural Resources, S. Rep. No. 272, 96th Cong., 1st Sess., (1979)), at 27 ("It is intended that the Administrator include in contract implementing this section provisions governing termination and resumption of any previously-terminated exchange, for the purpose of minimizing disruption of the Administrator's rate-making or power marketing programs or planning.").

Suspension Right

The statutory termination right afforded by section 5(c)(4) is only applicable if the utility's ASC falls below BPA's PF Exchange rate because of the application of the section 7(b)(3) surcharge. In the 2008 RPSA, BPA included an additional right in the RPSA to "suspend" a utility's participation in the REP for any reason.[76] This right could be exercised regardless of whether the section 7(b)(3) surcharge was the cause of the utility's ASC falling below BPA's PF Exchange rate. Because this suspension right was unilateral and only in favor of the utility, it required the utility to suspend its participation for the duration of the RPSA's term.[77] Thus, once exercised, the utility was precluded from re-entering the REP.

Deemer Account / Balancing Account

A third option developed through prior RPSAs is the concept of a "deemer" or "balancing account."[78] Instead of terminating or suspending its RPSA, a utility whose ASC fell below BPA's PF Exchange rate could "deem" its ASC equal to BPA's PF Exchange rate, thereby avoiding the payment to BPA. BPA would then track the net difference between the utility's ASC and BPA's PF Exchange rate in a separate account (a "deemer account" or "balancing account"). Thus, for instance, if BPA's PF Exchange rate was \$60/MWh and the utility's ASC \$50/MWh, BPA would not charge the utility but track the \$10/MWh difference in an account maintained by BPA. The utility would continue to file ASCs and participate in the exchange, with the negative net difference between BPA's rate and the utility's ASC accumulating in the deemer account. Once the utility's ASC exceeded BPA's PF Exchange rate, BPA would calculate the utility's REP benefits but would use those payments first to pay down the utility's "deemer" balance before allowing the utility to receive positive REP benefits.

Each of these components – (1) termination and reentry terms, (2) suspension, and (3) deemer accounts – will need to be revisited and considered under a traditional RPSA.

3.4.5 In-lieu Provision

As described above, section 5(c)(5) provides BPA the discretionary right to reduce the cost of the REP through purchases of power from "other sources" in lieu of purchasing power from the exchanging utility at their ASC. While the main transaction of the REP has always been implemented as a financial transaction, the *in lieu* provisions of section 5(c)(5) have always included (though not required) a physical sale of power to the exchanging utility. That is, BPA could acquire power from "other sources" and sell this power to the exchange utility "in lieu" of the utility selling its power to BPA at the utility's ASC. The rationale underlying this transaction is that the *in lieu* power sold from BPA would be used by the utility to serve its actual load, thereby

[76] *See* Short-Term Bridge Residential Purchase and Sale Agreement for the Period FY 2009-2011 and Regional Dialogue Long-Term Residential Purchase and Sale Agreement for the Period FY 2012-2028, Administrator's Record of Decision, Attachment B, § 11.2 (Sept. 4, 2008) (2008 RPSA), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2008-rod/rod-20080904-rpsa-record-of-decision.pdf.
[77] *Id.* ("Such suspension shall become effective as of the date specified in the notice, and shall suspend the rights and obligations of both Parties as of such date, and such suspension shall continue through September 30, 2028.")
[78] *See* 1981 RPSA § 10 (Election to Equalize Rates) (on file with BPA); 2008 RPSA § 12 (Balancing Account).

reducing the need for that utility to use its own, more expensive, resources. Both the 1981 RPSA and the 2000 RPSA included specific provisions and timelines for delivering physical *In-Lieu* energy. The 1981 RPSA required 7 years prior notice before BPA could implement the *in lieu* provision; the 2000 RPSA reduced this to 30 days. Both the 1981 and 2000 RPSAs also included the option for the utility to reduce its ASC to equal the *in lieu* purchase in order to not receive the physical *in lieu* power. The 2008 RSPA did not define a specific timeframe or terms for *in lieu* purchases but pointed to the subsequent development of an *in lieu* Policy.

BPA has never implemented an *in lieu* purchase. Further, the last drafted terms regarding *in lieu* are now over 20 years old. As such, BPA will need to develop modern terms to implement the *in lieu* provision. This provision will need to meet the requirements of section 5(c)(5), while also reflecting the new reality of modern power markets. Among other issues to consider will be the following:

- Rate applicable to *in lieu* purchase (PF Exchange rate or the *in lieu* cost of power)
- Source of *in lieu* power
- Notice and timing requirements for *in lieu* power
- Duration of sales
- Size of sale
- Options and elections to avoid *in lieu* deliveries (*e.g.,* reducing a utility's ASC to equal the cost of the *in lieu* power)
- Scheduling provisions
- Interaction with organized markets

3.4.6 RPSA Development and Public Comment Process

While the RPSAs will not be operative until October 1, 2028, it is BPA's objective to develop and offer final RPSAs for the post-2028 period as soon as practicable. Provided below are two tentative timelines for regional stakeholder consideration. The first timeline is designed to provide a more robust customer and stakeholder engagement process for determining the RPSA's terms. The second timeline, referred to as an "accelerated timeline," is designed to reach the RPSA's terms on an expedited basis, with the final record of decision and contract offers made by the end of 2025. The faster pace of the accelerated timeline necessarily means fewer opportunities for stakeholder engagement before the final terms of the RPSA are provided for public comment and final decisions. BPA is looking for regional stakeholder feedback on which of these two timelines parties support.

A visual process timeline is provided in the Appendix.

Timeframe	Event
September-November 2025	Workshops to develop RPSA terms
November-December 2025	RPSA Template released for comment
February 2026	RPSA Final ROD and Offers
March 2026	Execution of RPSAs

Alternative (accelerated) timeline:

Timeframe	Event
September 2025	Workshops to develop RPSA terms
October 2025	RPSA Template released for comment
December 2025	RPSA Final ROD and Offers
February 2026	Execution of RPSAs

3.5 Average System Cost Methodology

3.5.1 Overview

The average system cost, or ASC, is the cost of an exchanging utility's resources.[79] BPA develops an ASC Methodology to determine which resource costs are included in the ASC calculation for each utility. Section 5(c) of the Northwest Power Act provides BPA with limited direction on how to develop this methodology in consultation with the Council, BPA customers, and state regulatory bodies.[80] BPA has developed three ASC Methodologies over the last 40 years, the latest of which was developed in 2008. The ASC Methodology must be reviewed and approved by FERC.[81]

3.5.2 Post-2028 ASC Methodology

The 2008 ASC Methodology has proven to be a resilient and efficient methodology for calculating utility ASCs. The predecessor ASC Methodology – developed in 1984 – was the source of almost constant controversy. It was challenged multiple times in Court.[82] Even after being sustained by the Court, BPA's determination of utilities' ASCs under the 1984 ASC Methodology were routinely challenged, resulting in dozens of cases before FERC[83] and two at the Ninth Circuit.[84]

The 2008 ASC Methodology, by contrast, has operated for over 17 years without a single case filed at FERC or the Court. BPA believes the lack of controversy largely stems from the straightforward approach to calculating ASCs adopted in the 2008 ASC Methodology and the impact of the 2012 REP Settlement. While the 2008 ASC Methodology has performed well, it will be 20 years old at the time of the expiration of the 2012 REP Settlement. With significant changes in energy markets, regulatory landscape, and resource portfolios occurring now and continuing into the future, a fresh look at the ASC Methodology for the post-2028 period will be warranted.

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[79] *See* 16 U.S.C. § 839c(c)(1).
[80] *See* 16 U.S.C. § 839c(c)(7).
[81] *Id.* ("Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission.")
[82] *See Pub. Util. Comm'n of Or. v. Bonneville Power Admin.*, 767 F.2d 622 (9th Cir. 1985)*; Pac. Power & Light v. Bonneville Power Admin.*, 795 F.2d 810 (9th Cir. 1986), *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986).
[83] *See e.g,. Portland General Electric Co.,* 29 F.E.R.C. ¶ 61,044, (1984); *Idaho Power Co.,* 37 F.E.R.C. ¶ 61,104 (1986); *Pacific Power & Light Co.*, 37 F.E.R.C. ¶ 61,105 (1986); *Montana Power Co.*, 37 F.E.R.C. ¶ 61,103 (1986); *Puget Sound Power & Light Co.*, 75 F.E.R.C. 61,239 (1996).
[84] *See Wash. Util. & Transp. Comm'n v. FERC*, 26 F.3d 935 (9th Cir. 1994); *CP Nat. Corp. v. Bonneville Power Admin.*, 928 F.2d 905 (9th Cir. 1991).

This section of the REP Comprehensive Plan describes the essential components of the 2008 ASC Methodology, areas of considered improvements, and a timeline for reviewing and considering these changes.

3.5.2.1 Statutory Guidance

Section 5(c)(1) requires BPA to purchase power from an exchanging utility at that utility's "average system cost of that utility's resources . . . " The term "average system cost" is to be determined by the Administrator, in consultation with the Council, customers, and state regulatory bodies, but pursuant to a methodology. In determining the average system cost of resources the Administrator must exclude:

> (1) "the cost of additional resources in an amount sufficient to serve any new large single load of the utility. . ."
>
> (2) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and
>
> (3) any costs of any generating facility which is terminated prior to initial commercial operation.[85]

Apart from these exclusions, the Northwest Power Act has limited guidance on how BPA should develop the ASC Methodology.

3.5.2.2 General Approach

In very general terms, a utility's ASC of resources is calculated by the following formula:

Utility's Contract System Costs / Utility's Contract System Load = ASC.

The ASC Methodology identifies the type of costs that qualify as a "contract system costs" and the loads that qualify as the utility's "contract system load."

Under the 1984 ASC Methodology, a participating utility was required to submit a new ASC filing with BPA every time the utility implemented a change in its retail rates.[86] These filings were then reviewed by BPA in a 210-day ASC review process. With upwards of ten utilities participating in the REP during the 1980s, many with retail consumer in multiple states, the 1984 ASC Methodology resulted in BPA and its customers "almost always reviewing an ASC filing."[87] This approach also meant that the amount of REP payments BPA was making to the utilities was constantly changing, as updated ASCs varied from BPA's rate case forecasts of those ASCs. To stem the tide of filings, simplify the process, and minimize divergence from the rate case forecast, the 2008 ASCM moved away from jurisdictional filings and turned to a utility's FERC Form 1 as the source data for its ASC calculation.

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[85] 16 U.S.C. §§ 839c(7)(A)-(B).

[86] *See* 2008 Average System Cost Methodology, Final Record of Decision, at 8 (June 30, 2008) (2008 ASCM ROD) *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2008-rod/rod-20080630-final-2008-asc-methodology-rod.pdf.

[87] 2008 ASCM ROD at 11.

The FERC Form No. 1 "is a comprehensive financial and operating report submitted annually for electric rate regulation, market oversight analysis, and financial audits by Major electric utilities, licensees and others."[88] The 2008 ASCM Methodology relies on historical FERC Form 1 data– usually a year before the applicable BPA rate proceeding. Once the Contract System Costs and Contract System Loads are calculated using historic data, a "Base Period" ASC is determined. The Base Period ASC is then adjusted by a forecast model to bring the utility's ASC into the dollars and prices that will apply during the current rate period (called the Exchange Period). This escalated ASC is called the Exchange Period ASC. The Exchange Period ASC is the ASC that will be used to calculate that utility's payments under the REP.

Overall, the use of historic FERC Form 1 data as the source of information for calculating a utility's ASC has been an efficient and streamlined method for determining the cost of resources and loads for a utility.

3.5.2.3 Procedures and Process

The process for determining a utility's ASC is set forth in BPA's Rules of Procedure for BPA's ASC Review Processes.[89] These rules were originally developed as part of the 2008 ASC Methodology. However, when reviewing the ASC Methodology, FERC removed references to BPA's rules of procedure, noting that "[t]he procedures established by Bonneville's Administrator provide the filing requirements for all Utilities that file an Appendix 1 with Bonneville. Utilities must file Appendix 1s, ASC forecast models, and other required documents with Bonneville in compliance with Bonneville's ASC review procedures."[90] Separate from its Rules of Procedure, BPA developed Confidentiality Rules to enable parties to provide and receive information on resources and loads, subject to restrictions on use and dissemination.

BPA will likely be considering whether to revisit its procedures and process for reviewing ASCs. While the current processes have worked well, certain base assumptions on the timing of this process, and its interaction with BPA rate cases, could use improvement.[91] BPA intends to explore this issue concurrent with or at the end of its review of the ASC methodology.

3.5.2.4 Transmission

As discussed above, the REP under the Northwest Power Act is designed to address wholesale power cost rate disparity by allowing a utility to sell power to BPA at that utility's average system cost of resources. The Northwest Power Act defines "resource" to mean "electric power, including the actual or planned electric power capability of generating facilities" or "actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure."[92] Based on this definition, the Northwest Power Act does not directly

[88] https://www.ferc.gov/industries-data/electric/resources/industry-forms/form-no-1-annual-report-major-electric-utility.

[89] The rules are available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/asc-fy-2022-2023/asc-rules-of-procedure-final-05-22-2012.pdf.

[90] 18 C.F.R. § 301.4(a).

[91] For instance, BPA intends to update the conditions and requirements for customers to request a consultation process on the ASCM. *See* 18 C.F.R. § 301.5(a).

[92] 16 U.S.C. § 839a(19)(A)-(B).

state that a "transmission costs" *i.e.,* the cost of transmitting power from a resource to the load, should be included in a utility's ASC.

BPA has historically included transmission costs into a utility's ASC as a matter of "policy."[93] In the 1981 ASC Methodology, all of a utility's transmission costs were included. BPA modified this approach in the 1984 ASC Methodology, limiting transmission costs to existing transmission facilities, and excluding future transmission expansions.[94] This approach proved cumbersome to implement and, thus, BPA abandoned the partial inclusion of transmission in the 2008 ASC Methodology and returned to the full inclusion of transmission costs in ASC.[95]

BPA believes revisiting the inclusion of transmission in a utility's ASC is appropriate for the post-2028 implementation of the REP. This would include revisiting whether the justifications and rationale described in the 2008 ASC Methodology for including all transmission costs in a utility's ASC remain sound. By raising this issue, BPA is not taking a position on whether to include or exclude transmission costs. BPA intends to consider this issue in the process designed to address revisions and updates to the ASC Methodology.

3.5.2.5 New Resource Additions

Under the 1984 ASC Methodology, new resource costs would be reflected every time the utility implemented a change in retail rates because the methodology required such utility to submit a new ASC filing. Under the 2008 ASCM, the FERC Form 1 is based on historic data, meaning the Base Period ASC naturally omits new resource costs the utility had (or would) acquire after publication of the FERC Form 1. The Base Period ASC would also not capture resource cost reductions the utility may experience with the retirement or expiration of an existing resource.

To account for this gap, the 2008 ASCM allows a utility to update its Exchange Period ASC for major new resource additions or reductions. Consequently, ASC adjustments may cause fluctuations in REP benefits. These new resource costs may occur in two different time frames. First, they may occur between the Base Period ASC and the Exchange Period ASC. Second, the new resource addition or reduction may occur during the Exchange Period itself (after BPA sets its rates and the utility's Exchange Period ASC). In both instances, the 2008 ASCM allows the utility to adjust its Exchange Period ASC for these resource changes provided the change in ASC is at least 2.5 percent as compared to the utility's Base Period ASC.[96] The ASCM refers to this limit as the "Materiality Threshold." A utility can aggregate multiple new resource additions or reductions to meet this threshold, provided that each new resource cost was at least 0.5 percent.[97]

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[93] *See* 1984 Average System Cost Methodology, Administrator's Record of Decision, at 41 (June 4, 1984) (1984 ASCM ROD), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1984-rod/rod-19840604-average-system-cost-methodology.pdf ; 2008 ASCM ROD at 127.
[94] 2008 ASCM ROD at 127.
[95] 2008 ASCM ROD at 125-141.
[96] 18 C.F.R. § 301.4(c)(4).
[97] 2008 ASCM ROD at 47-48.

Under the 2012 REP Settlement, exchange participants agreed to waive their right to request changes to their ASCs for new resources coming online or offline during the Exchange Period.[98] The expiration of the 2012 REP Settlement will reactivate the provisions of the 2008 ASCM that allow utilities to update their Exchange Period ASCs for new resources through the Exchange Period, which consequently change the utility's REP benefits. As part of the ASCM review process, BPA may revisit different aspects relating to ASC adjustments for new resource additions or removals that include, but are not limited to, timing of projected major resource additions/removals, resource eligibility criteria, and the Materiality Thresholds.

3.5.2.6 Resources to Serve a New Large Single Load

As noted above, section 5(c)(7)(A) of the Northwest Power Act requires BPA to exclude from a utility's ASC "the cost of additional resources in an amount sufficient to serve any new large single load of the utility[.]"[99] A "new large single load", or "NLSL", is a load that was not "contracted for or committed to" by a BPA customer prior to September 1, 1979, and results in an increase in power requirements of such customer of "ten average megawatts or more in any consecutive twelve-month period."[100]

To implement this provision in the 2008 ASCM, BPA developed Endnote d to the Appendix 1.[101] The Appendix 1 is the electronic form on which a utility reports its Contract System Costs and other necessary data to BPA for the calculation of the utility's Base Period ASC. In general, Endnote d describes three methods for removing from a utility's ASC the cost of resources associated with an NLSL. First, if the utility uses "dedicated resources" to serve the NLSL, then the costs of those resources (plus transmission) are excluded from the utility's ASC.[102] Second, if the utility purchased power from BPA under BPA's New Resources ("NR") rate, then the costs to be removed from the utility's ASC are the costs of the NR rate.[103] If neither of these two subparts applies, then the cost of serving the utility's NLSL follows subpart (3).[104] Under subpart (3), BPA calculates the resource costs sufficient to serve an NLSL by calculating the weighted fully allocated cost for all of the utility's resources in-service and dedicated to the utility's retail load after September 1, 1979.[105]

In February 2012, BPA issued a Final Interpretation and Implementation of Endnote d(3) to address an implementation issue that was treating the resource costs associated with an NLSL differently than the treatment of those same costs in a utility's ASC.[106] BPA intends to revisit this

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98 2012 REP Settlement § 6.4.
99 16 U.S.C. § 839c(c)(7)(A).
100 16 U.S.C. § 839a(13)(A)-(B).
101 *See* 18 C.F.R. § 301, Appendix 1, En. d(1).
102 *See* 18 C.F.R. § 301, Appendix 1, En. d(1).
103 *Id.* at En. d(2).
104 *Id.* at En. d(3).
105 *Id.*
106 *See* Final Interpretation and Implementation of Endnote d(3) of the 2008 ASC Methodology (Feb. 2012), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/rep-14-endnote-d3-interpretation20120221-2012.pdf.

implementation to determine whether to codify this approach in the ASCM to ensure this treatment is maintained in the future.

3.5.2.7 Public Exchange Provisions

Section 5(c) permits any utility in the region to participate in the exchange, including public customers. As such, since passage of the Northwest Power Act, public utilities have participated in the REP. In order to preserve the value of the low-cost Federal power system, public customers agreed to a partial waiver of their rights to participate in the REP under the Regional Dialogue contract.[107] To accommodate this partial waiver, the 2008 ASCM included special provisions for participating public customers with Regional Dialogue Contracts.[108]

In the Provider of Choice Policy, BPA expanded the REP limited waiver. For the Provider of Choice contracts, BPA included "a provision whereby PF customers would waive their participation in the REP for the Provider of Choice contract period."[109] Consistent with this decision, BPA will revise the 2008 ASCM and remove provisions related to a partial waiver of the REP for public participants. Additionally, BPA will need to ensure the remaining provisions of the ASCM will be applicable to public customers that choose not to take a Provider of Choice contract.

3.5.3 Average System Cost Methodology Consultation Process

A tentative process timeline for the ASCM consultation process and publication of a new ASCM is provided below. If the "accelerated" timeline for the RPSA is chosen, then the ASCM process will be delayed until next year to permit BPA staff and regional parties to focus on completing the RPSA by the end of 2025. A visual process timeline is provided in the Appendix.

Timeframe	**Event**
October – December 2025	Workshops to review ASCM terms
January – February 2026	Draft ASCM open for comment (30 days)
March 2026	Final ASCM and ASCM ROD
April 2026	File ASCM with FERC

Alternative timeline if the accelerated RPSA timeline is adopted:

Timeframe	**Event**
January-March 2026	Workshops to review ASCM terms
March-April 2025	Draft ASCM open for comment (30 days)
May 2025	Final ASCM and ASCM ROD
June 2026	File ASCM with FERC

[107] *See* Bonneville Power Administration, Long-Term Regional Dialogue Contract Policy, Administrator's Record of Decision, at 30 (Oct. 31, 2008), *available at* https://www.bpa.gov/-/media/Aep/power/regional-dialogue/cp-rod-final-version-10-31-08-web.pdf.
[108] 18 C.F.R. § 301.4(g).
[109] PoC Policy at § 10.1.

3.6 Sections 7(b)(2) and 7(b)(3)

3.6.1 Overview

As noted above, the REP involves two offsetting sales of power, one from the utility at their ASC and one from BPA at the PF Exchange rate. The PF Exchange rate is BPA's cost of power, modified by certain rate adjustments as provided for in sections 7(b)(1), 7(b)(2), and 7(b)(3) of the Northwest Power Act. Only utilities participating in the REP are charged the PF Exchange rate.

To calculate the PF Exchange rate, BPA follows the ratemaking steps called for in section 7(b). Section 7(b)(1) requires BPA to establish a rate that recovers the collective costs of serving the general requirements load of both public customers and the residential and farm loads of IOUs participating in the REP.[110] The section 7(b) rate begins, initially, at the same level for both public power and IOU's participating in the exchange. BPA then performs a statutory rate test, known as the section 7(b)(2) rate test, to determine whether the preference customer rate should be protected from certain costs created by the Act (including the REP).[111] The rate test effectively creates a ceiling on the costs BPA can recover from its preference customers' PF rate. If the rate ceiling is reached, then the costs exceeding that ceiling must be allocated to other power sold by BPA.[112] This allocation occurs through application of a surcharge created by section 7(b)(3).[113] The PF Exchange rate is one of the rates that receives the costs allocated away from the preference customers' rate as a result of the section 7(b)(2) rate test.[114] In general terms, as costs are allocated away from the preference customer's rates by the 7(b)(2) rate test, the PF Exchange rate increases, and REP benefits decrease.

The section 7(b)(2) rate test is a complicated provision of the Northwest Power Act.[115] The rate test requires BPA to compare a rate that includes some (but not all) of the costs that BPA would be charging public customers during the rate period with a hypothetical rate that removes certain features of the Northwest Power Act. If the hypothetical rate is higher than the rate BPA intends to charge public customers, nothing happens – BPA may charge the rate it proposes without adjustment. If, however, the hypothetical rate is *lower* than the rate BPA intends to charge public customers, then the 7(b)(2) rate test "triggers." In that case, BPA must remove costs from the

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[110] *See* 16 U.S.C. § 839e(b)(1).
[111] *Id.* at § 839e(b)(2).
[112] Senate Report (Senate Comm. On Energy and Natural Resources, S. Rep. No. 272, 96th Cong., 1st Sess., (1979)), at 15. *See also* House Report (Commerce) (House Comm. on Interstate and Foreign Commerce, H.R. Report No. 976, 96th Cong., 2d Sess., pt. 1) (May 14, 1980), at 34 ("[s]ection 7(b) reserves for preference customers the price benefits of Federal power that they would have enjoyed in the absence of this legislation. This is accomplished by a 'rate ceiling' which governs preference customer general requirements rates.") *See also Portland Gen. Elec. v. Bonneville Power Admin.*, 501 F.3d 1009, 1015-16 (9th Cir. 2007).
[113] 16 U.S.C. § 839e(b)(3).
[114] *Id*.
[115] A former BPA Administrator once quipped that section 7(b)(2) was "a Byzantine sentence that nearly fills a page and that is, in my view, the most complicated section in the Act." WP-07 Supplemental ROD, at xv (Administrator's Preface).

public's power rate, and allocate those costs to the rates of "all other power sold" by BPA.[116] This includes the PF Exchange rate.

To assist in interpreting the requirements of section 7(b)(2), BPA has historically developed both a legal interpretation and 7(b)(2) implementation methodology. The legal interpretation is designed to state BPA's position on certain legal issues relating to the approach BPA intends to take when implementing the 7(b)(2) rate test. These legal interpretations are then used in the 7(b)(2) Implementation Methodology, which describes the steps and assumptions BPA uses to produce the rate test results.

The first 7(b)(2) Legal Interpretation and 7(b)(2) Implementation Methodology were developed in 1984.[117] Both were subsequently revised in 2008 as part of the WP-07 Supplemental Rate proceeding (2008 7(b)(2) Legal Interpretation and 2008 7(b)(2) Implementation Methodology).[118] These revisions were challenged as part of the cases brought before the Ninth Circuit in 2008. In the 2012 REP Settlement, BPA agreed to withdraw both its 7(b)(2) Legal Interpretation and Implementation Methodology and accept the settlement terms instead.[119] The 2012 REP Settlement requires BPA to "conduct a proceeding and issue a record of decision to determine, for the period starting with Fiscal Year 2029, whether, and if so, how, to modify or replace its legal interpretation of, and methodology for implementing, sections 7(b)(2) and 7(b)(3)" of the Northwest Power Act.[120]

In addition to the 7(b)(2) Legal Interpretation and Implementation Methodology, BPA relies on a Rates Analysis Model (RAM) to perform the calculations called for in section 7(b)(2). BPA intends to modify RAM in accordance with the 7(b)(2) Implementation Methodology and Legal Interpretation during the public process described below. While BPA intends to make all necessary changes to RAM to align it with the Legal Interpretation and Implementation Methodology during the 7(b)(2) process described below, some variation may arise between the model presented during the public process and the BP-29 rate proceeding due to timing of decisions and incorporating other rate elements. RAM is updated every rate period with current information; as a result, the model presented during the 7(b)(2) public process will rely on data from the BP-26 Rate Proceeding.

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[116] *See* 16 U.S.C. § 839e(b)(3).
[117] *See* Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984). *See also* Section 7(b)(2) Implementation Methodology, Administrator's Record of Decision, b-2-84-F-02, August 1984, *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1984-rod/rod-19840817-section-7b2-implementation-methodology.pdf.
[118] *See* Section 7(b)(2) of the NWPA Legal Interpretation, WP-07-A-06, Sept. 2008, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2008-BPAs-Legal-Interpretation-of-Section-7b2-of-the-NW-Power-Act.pdf; Section 7(b)(2) of the NWPA Implementation Methodology, WP-07-A-07, Sept. 2008, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/Extract-of-BPAs-Implementation-Methodology-2008.pdf.
[119] *See* REP-12 ROD, at 344-48.
[120] 2012 REP Settlement, § 11.3.

3.6.2 7(b)(2) Legal Interpretation and Implementation Methodology Processes

Consistent with its historic approach, BPA intends to issue both a legal interpretation and implementation methodology to perform the section 7(b)(2) rate test. BPA also intends to issue an updated RAM to before these calculations. BPA intends to use the section 7(i) process for developing these documents and models. This follows BPA's past practice. The legal interpretation, implementation methodology, and RAM will be used to perform the section 7(b)(2) rate test in the BP-29 rate case.

A tentative process timeline for the 7(b)(2) public process and 7(i) is provided below. A visual process timeline is provided in the Appendix.

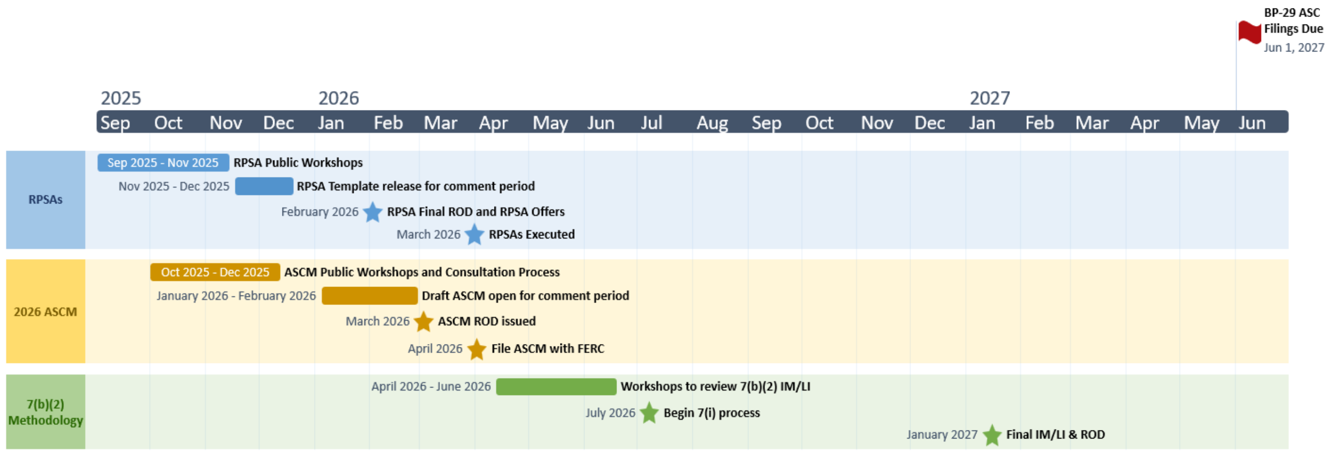
Timeframe	Event
April-June 2026	Workshops to review 7(b)(2) IM/LI
July 2026	Begin Section 7(i) on Section 7(b)(2) IM/LI
January 2027	Final IM/LI on Section 7(b)(2) and ROD

4 Next Steps

As discussed above, BPA has scheduled a hybrid workshop in the BPA Rates Hearing Room on **Monday, July 28, 2025, at 9:00am** to discuss the timelines and processes addressed herein.[121] BPA is also seeking stakeholder feedback on these timelines by **August 7, 2025**. Workshop details can be found on BPA's Event Calendar. Comments on the timelines may be submitted to the Post-2028 REP inbox: rep2028@bpa.gov.

[121] Meeting information is available here: https://www.bpa.gov/learn-and-participate/public-involvement-decisions/event-calendar/event-details?pageid=%7bAD38A0F6-678E-4E82-AC3F-AB0CFC6C206D%7d.

5 Appendix – Visual Timelines



<u>Alternative RPSA and ASCM timelines:</u>