Residential Exchange Program

ADMINISTRATOR'S DRAFT RECORD OF DECISION

2026 AVERAGE SYSTEM COST METHODOLOGY

September 11, 2026

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COMMONLY USED ACRONYMS AND SHORT FORMS

aMW	average megawatt(s)
ASC	Average System Cost
ASCM	Average System Cost Methodology
BAA	Balancing Authority Area
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
CGS	Columbia Generating Station
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
Council	Northwest Power and Conservation Council (see also "NPCC")
CRAC	Cost Recovery Adjustment Clause
CY	calendar year (January through December)
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FY	fiscal year (October through September)
GRSPs	General Rate Schedule Provisions
GWh	gigawatthour
IOU	investor-owned utility
IP	Industrial Firm Power
kW	kilowatt
kWh	kilowatthour
MW	megawatt
MWh	megawatthour
NEPA	National Environmental Policy Act
NLSL	New Large Single Load
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council
NR	New Resource Firm Power
NRU	Northwest Requirements Utilities
OATT	Open Access Transmission Tariff
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNRR	Planned Net Revenues for Risk
POD	Point of Delivery
PUD	public or people's utility district
REC	Renewable Energy Certificate

REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement

1.0 INTRODUCTION

Bonneville Power Administration (BPA) is statutorily responsible for establishing a methodology for determining the average system cost (ASC) of resources for regional electric utilities that participate in the Residential Exchange Program (REP). Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act or NWPA) established the REP and authorizes the BPA Administrator to determine utilities' ASCs based on a methodology developed by the Administrator in consultation with the Northwest Power and Conservation Council, BPA customers, and state regulatory agencies in the Pacific Northwest.[1] The ASC Methodology (ASCM) is used in the determination of monetary benefits paid by BPA to utilities participating in the REP. The existing ASCM was adopted by BPA and approved by the Federal Energy Regulatory Commission (FERC or Commission) in 2008 (2008 ASCM).[2]

This Record of Decision (ROD) sets forth BPA's draft determinations regarding the terms and conditions of the 2026 Average System Cost Methodology (2026 ASCM). The 2026 ASCM will be used to establish a utility's average system cost of resources (ASC), as used in the energy-neutral purchase and sale established by Section 5(c)(1) of the Northwest Power Act.[3]

The 2026 ASCM is a rule of both BPA and FERC.[4] The Commission must "review and approve" the 2026 ASCM.[5] The 2026 ASCM is comprised of two parts: Part I contains the terms of the ASCM to be published in FERC's regulations (18 C.F.R. § 301.1-7); Part II contains BPA's rules of procedure for determining a utility's ASC. BPA intends to file Part I of the ASCM with FERC within a few weeks of the issuance of the final ROD, with a request for interim approval of the 2026 ASCM by early 2027.

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[1] *See* 16 U.S.C. § 839c(c)(7).
[2] *See Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology,* 124 FERC ¶ 61,312 (Sep. 30, 2008) (interim approval); *Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology,* Order No. 726, 74 Fed. Reg. 47,052 (Sep. 15, 2009) (final approval).
[3] 16 U.S.C. § 839c(c)(1).
[4] *See Cent. Elec. Coop. v. Bonneville Power Admin.*, 835 F.2d 199, 204 (9th Cir. 1987).
[5] 16 U.S.C. § 839c(c)(7).

2.0 BACKGROUND

2.1 Historical Context for the Residential Exchange Program

The REP was created by Congress to address long-standing regional disputes concerning rate disparities between public and private utilities in the Pacific Northwest. BPA, a power marketing administration, is responsible for selling and transmitting power from 31 federal hydroelectric projects and one non-federal nuclear plant.[6] BPA sells its power and transmission at cost, without profit. Federal law mandates that BPA prioritize power generated at federally owned and operated projects for not-for-profit public bodies and cooperatives, collectively known as "Public Power" customers.[7] Any remaining power, after meeting Public Power customer demands, may be sold to non-preference customers, including regional for-profit utilities (investor-owned utility customers or IOUs) and direct service industries (DSIs).[8]

Until the 1970s, BPA had sufficient power to meet the collective demands of Public Power customers, IOUs, and DSIs throughout the Pacific Northwest.[9] However, by the early 1970s, regional projections indicated that BPA's supply of federal power would be needed to meet the needs of its Public Power customers. Because of the preference and priority provisions of the Bonneville Project Act, 16 U.S.C. § 832c(a)-(b), BPA would not be able to meet the needs of non-preference entities (IOUs and DSIs) on a long-term basis. In response to this impending shortage, BPA began limiting its commitment to serving non-preference customers' power needs. In 1973, BPA ceased making long-term firm power sales to IOUs.[10] Subsequently, BPA informed the DSIs that their contracts would not be renewed upon expiration during the 1981-1991 period.[11]

With the loss of BPA power, the IOUs had to invest in alternative, higher-cost thermal resources. These increased costs were passed on to their retail consumers, leading to higher retail rates for customers in IOU-served areas.[12] Significant cost disparities soon emerged between the rates paid by Public Power end-use consumers and IOU end-use

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[6] 16 U.S.C. §§ 832f, 838g, 839e(a)(1)-(2); *see also* Bonneville Power Administration, BPA Facts (Oct. 2025), *available at* https://www.bpa.gov/-/media/Aep/about/publications/general-documents/bpa-facts.pdf.
[7] *See* 16 U.S.C. § 832c(a). The Public Power customers are also sometimes called "preference customers" or "Consumer-Owned Utilities" or COUs because they are largely owned by consumers and afforded preferential rights to the sale of available federal power. In this ROD, they will be referred to as "Public Power customers."
[8] The DSIs are large industrial customers that purchased power directly from BPA. These included aluminum plants, steel mills, wood and pulp production, and other large production loads.
[9] *See* H.R. Rep. No. 96-976, pt. I, at 23–26 (1980).
[10] *See Aluminum Co. of Am. v. Cent. Lincoln Peoples' Util. Dist.* (*Alcoa*), 467 U.S. 380, 385 (1984).
[11] *Id.*
[12] H.R. Rep. No. 96-976, pt. II, at 30 (1980) ("However, since 1973, when BPA stopped selling power to IOUs, they have had to rely on (as it has turned out) increasingly expensive thermal power. Preference customers, on the other hand, still rely primarily upon low cost Federal hydro. Consequently, wholesale power costs to IOUs are usually higher than those faced by preference customers in the region. Since Oregon is primarily served by IOUs and Washington is primarily served by preference customers, consumers in Oregon (and Idaho and western Montana), on the average, pay more for their electricity at retail than those in Washington.").

consumers, with IOU customers sometimes paying up to three times more for power.[13] To address these disparities, state legislatures passed competing laws aimed at broadening the scope of utilities eligible to purchase BPA's low-cost power as a Public Power customer.[14] This led to litigation and other attempts to expand access to BPA's power.[15] The situation escalated to a point where the Northwest was "poised for [a] regional civil war—an interstate battle over the allocation of low-cost federal power."[16]

In 1980, Congress responded by passing the Northwest Power Act.[17] The Northwest Power Act was intended to provide a "comprehensive solution" to the looming power disputes.[18] Congress' aim was to "avoid the prospect of unproductive and endless litigation" among BPA's customer groups by creating a legislative framework to resolve these numerous issues.[19]

A key component of the Northwest Power Act is Section 5(c), which created the Residential Exchange Program or REP.[20] Through the REP, residential and farm[21] consumers of higher-cost Pacific Northwest utilities (primarily IOUs) receive a rate benefit from the low-cost federal power reserved by federal statute to Public Power customers. This rate benefit comes in the form of an energy-neutral purchase and sale, where utilities with higher-cost resources sell power to BPA at their average system cost of resources (ASC).[22] BPA, in turn, concurrently 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. Since these sales are equal and offsetting, this "exchange" has always been implemented as a financial transaction, with no actual power transferring between the parties. BPA pays the utility the net

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[13] Post 2028 Residential Exchange Program presentation at 13 (Sept. 27, 2022) (quoting Gov. of Oregon Straub in an article from the Oregonian (Apr. 12, 1978): "People in Portland are paying $27 for electricity people in Vancouver are paying $11 for . . . . The general public should have equal access."), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/092722-Post-2028-REP-Phase-1-Kickoff-WorkshopV4.pdf.

[14] H.R. Rep. No. 96-976, pt. II, at 30 (1980) (describing the state of Oregon's development of a Domestic Rural Power Authority, the City of Portland lawsuit, and "efforts . . . being made . . . elsewhere in the region to form new 'public bodies and cooperatives' eligible to receive Federal hydro from BPA.").

[15] *Id.* ("On November 14, 1977, the City of Portland, Oregon, filed two lawsuits against BPA in Federal District Court in Portland in an attempt to secure Federal hydro from BPA for the city, which is presently served by two investor-owned utilities.").

[16] *Pacific Northwest Electric Power Supply and Conservation: Hearings on H.R. 9020, H.R. 9664, and H.R. 5862 Before the Subcomm. on Water & Power Resources of the H. Comm. on Interior & Insular Affairs, 95th Cong.*, Pt. I, 133 (Dec. 5, 1977) (statement of Dixy Lee Ray, Governor of Washington); *see also* H.R. Rep. No. 96-976, pt. I, at 27 (1980) (noting the legislation would avert a "regional civil war" over low-cost power).

[17] *See* 16 U.S.C. § 839 *et seq*.

[18] *Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1107 (9th Cir. 1984).

[19] *Alcoa*, 467 U.S. 380, 386 (1984).

[20] *See* 16 U.S.C. § 839c(c)(1). The term "residential exchange program" comes from the concept that the utility's residential load was the determining factor for the amount of power "exchanged" under Section 5(c)(1). *See* H.R. Rep. No. 96-976, pt. II, at 34 (Sep. 16, 1980) (describing a "Residential power 'exchange.'")

[21] 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).

[22] 16 U.S.C. § 839c(c)(1).

difference between the two sales (ASC-PF Exchange Rate), multiplied by the utility's qualifying residential and farm load (exchange load).

A simplified example illustrates how the REP benefit has been calculated:

Base Data	
IOU's average system cost of resources (ASC)	$85.00/MWh
BPA's cost of power (PFx Rate)	$55.00/MWh
IOU's Residential and Farm Load	100 MWh

Simplified Traditional REP Calculation[23]
(ASC - PFx Rate) x Residential Load = REP benefit ("cost benefits")
($85/MWh - $55/MWh) x 100MWh = $3000 (payment by BPA to IOU).

The Act mandates that the "cost benefits" of this energy-neutral exchange (*i.e.,* the REP benefit) be passed on by the utilities to their retail residential and farm consumers, typically as a credit on their retail power bill.[24] In this way, "the exchange program is designed to provide rate relief for consumers served by IOUs."[25]

2.2 Paying for the Costs of the Residential Exchange Program

As Congress was developing the REP as part of the Northwest Power Act, Public Power customers expressed concern that the REP would increase their power costs under the power rate created by the Act (called the Priority Firm or PF rate). Congress included two provisions to alleviate this concern. First, for the initial four years of the Northwest Power Act (1981-1985), the costs of the REP benefit would be paid for by the power rates BPA charged the DSIs.[26] At that time, the DSIs accounted for approximately 30 percent of BPA's load.[27] After July 1, 1985, the cost of the REP could be recovered from BPA's power rates to other customer classes, including the power rate BPA charges to Public Power customers, (*i.e.,* the PF rate).[28]

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[23] In *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.* (*APAC*), 733 F.3d 939, 956 (9th Cir. 2013), the Court calls this calculation the "traditional section 5 formula."
[24] 16 U.S.C. § 839c(c)(3).
[25] *Alcoa*, 467 U.S. at 398.
[26] *See* 16 U.S.C. § 839e(c)(1)(A); *see also* H.R. Rep. No. 96-976, pt. II, at 35 (1980) ("Customers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since, as discussed below, the direct-service industrial customers of BPA are required to pay the costs of the exchange during its initial years while a 'rate ceiling' protects the customers of preference utilities during later years."); H.R. Rep. No. 96-976, pt. I, at 61 (1980) ("The cost of the exchange during the first five years is charged to the rates applicable to DSI's under section 7(c)(l)(A).").
[27] 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.
[28] 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.

Second, Congress added a special rate test in the Northwest Power Act in Section 7(b)(2).[29] The Section 7(b)(2) rate test requires BPA to test Public Power's proposed PF rate against a hypothetical rate adjusted for certain assumptions, one of which is to assume no costs of the REP are incurred.[30] If the hypothetical rate is lower than the PF rate BPA would have charged Public Power, the rate test "triggers," meaning BPA must allocate the cost difference to other non-PF rates, including the PF Exchange rate BPA uses to calculate REP benefits. One effect of this reallocation is that the PF Exchange rate increases through a supplemental surcharge, which in turn decreases the difference between the ASC and the PF Exchange rate. Ultimately, when the Section 7(b)(2) rate test triggers, the total amount of REP costs paid for by Public Power through the PF rate decreases, and all else equal, overall REP benefits also decrease.[31]

Presently, seven regional utilities participate in the REP: six IOU utilities and one Public Power customer. BPA has only one remaining DSI customer, which represents roughly 0.01 percent of BPA's load.[32] The current agreements implementing the REP expire on September 30, 2028. At the expiration of the current REP agreement, BPA will have paid over $11 billion to regional utilities in REP payments under Section 5(c) (*i.e.,* 1981-2028).[33]

2.3 Components to Implement the REP: RPSA, ASCM, and 7(b)(2) Legal Interpretation and Methodology

The REP benefit payment is informed by three primary documents: 1) Residential Purchase and Sale Agreement (RPSA); 2) Average System Cost Methodology (ASCM); and 3) Section 7(b)(2) Legal Interpretation and Implementation Methodology. Each of these component parts is described below.

2.3.1 Residential Purchase and Sale Agreement (RPSA)

The Residential Purchase and Sale Agreement, or RPSA, sets out the contractual terms and conditions for engaging in the energy-neutral purchase and sale called for in Section 5(c). Most importantly, the RPSA contains the provisions that create and calculate the net payment described in Sections 5(c)(1)-(3).[34] Once the REP payment is determined, the RPSA requires the participating utility to pass the resulting "cost benefits" to its retail consumers, as required by Section 5(c)(3).[35] The RPSA also includes terms to implement other features of Section 5(c), such as termination rights (*see* Section 5(c)(4))[36] and replacing the energy-neutral exchange with a physical purchase from another source

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[29] *See* 16 U.S.C. § 839e(b)(2).
[30] *Id.* at § 839e(b)(2)(A)-(E).
[31] *Id.* at § 839e(b)(3).
[32] 2025 Pacific Northwest Loads and Resources Study at 16, Table 2-3 (May 16, 2025) (showing DSI load of 11 aMW), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf.
[33] Post-2028 Residential Exchange Program Comprehensive Plan - Traditional REP - Phase 2, at 3 (July 17, 2025) ("2025 REP Comprehensive Plan"), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep-comprehensive-plan.pdf.
[34] 16 U.S.C. § 839c(c)(1)-(3).
[35] 16 U.S.C. § 839c(c)(3).
[36] 16 U.S.C. § 839c(c)(4).

(*see* Section 5(c)(5)).[37] The RPSA also includes audit and compliance provisions to ensure the REP benefits are passed through directly to eligible regional residential and farm consumers.

BPA has developed four versions of the RPSA over the past 45 years: 1981, 1995, 2000, and 2008.[38] Additionally, in 2011, BPA developed a special form of the RPSA used in implementing the 2012 REP Settlement (*see* section 2.5 of this ROD) called a Residential Exchange Program Settlement Implementation Agreement (REPSIA).[39] On March 6, 2026, BPA issued the latest version of the RPSA—the 2026 RPSA—along with a Record of Decision.[40] The 2026 RPSA will apply to purchases and sales under the REP for the post-2028 period.

2.3.2 Average System Cost Methodology (ASCM)

The Average System Cost Methodology or ASCM establishes the rules for determining the utility's average system cost of resources (ASC) used in the REP benefit calculation. Section 5(c)(7) of the Northwest Power Act requires BPA to develop the ASCM, which is reviewed and approved by the Federal Energy Regulatory Commission (FERC).[41]

BPA has developed three ASC Methodologies over the last 40 years (1981, 1984, and 2008).[42] This process considers BPA revisions to the ASCM.[43]

2.3.3 Section 7(b)(2) Legal Interpretation and Implementation Methodology

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.[44] 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),

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[37] 16 U.S.C. § 839c(c)(5).

[38] 2025 REP Comprehensive Plan at 11 (noting three of the RPSAs, but omitting the 1995 RPSA which was offered as an alternative during the term of the 1981 RPSA); *see also* 1981 Template Residential Purchase and Sale Agreement (Aug. 22, 1981) ("1981 RPSA") (on file with author); 1995 Draft Residential Purchase and Sale Agreement Template (July 13, 1995) ("1995 RPSA") (on file with author) (the 1995 RPSA was offered as a replacement for the 1981 RPSA, which was still in effect); 2000 Residential Purchase and Sale Agreement Template (May 2, 2000) ("2000 RPSA") (on file with author); 2008 Residential Purchase and Sale Agreement Template (Sept. 12, 2008) ("2008 RPSA") (on file with author). All "on file with author" documents were made available on BPA's website under the heading Draft ASCM ROD, Sep. 11, 2026, Citations.

[39] 2025 REP Comprehensive Plan at 12; *see also* Residential Exchange Program Settlement Agreement Proceeding, Administrator's Final Record of Decision, REP-12-A-02, Appendix A, Residential Exchange Program Settlement Agreement, Exhibit A, Residential Exchange Program Settlement Implementation Agreement (July 26, 2011) ("REPSIA"), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2011-rod/rod-20110726-residential-exchange-program-settlement-agreement-proceeding-rep-12.pdf.

[40] *See* 2026 Residential Purchase and Sale Agreement, Administrator's Record of Decision, March 6, 2026 ("2026 RPSA ROD") *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2026-rod/rod-20260306-2026-residential-purchase-and-sale-agreement-record-of-decision.pdf.

[41] 16 U.S.C. § 839c(c)(7).

[42] 2025 REP Comprehensive Plan at 15.

[43] *Id.* at 20.

[44] *See* 16 U.S.C. § 839c(a) ("Such sales shall be at rates established pursuant to Section 839e of this title.").

and 7(b)(3) of the Northwest Power Act.[45] Only utilities participating in the REP are charged the PF Exchange rate.

To calculate the PF Exchange rate, BPA follows the ratemaking steps in Section 7(b). This includes the complex Section 7(b)(2) rate test discussed above. To assist in interpreting the requirements of Section 7(b)(2), BPA has historically developed both a legal interpretation and an implementation methodology.[46] The legal interpretation is designed to state BPA's position on certain legal issues relating to the Section 7(b)(2) rate test. These legal interpretations are then used in the Section 7(b)(2) Implementation Methodology, which describes the steps and assumptions BPA uses to produce the rate test results.

Under a settlement agreement (discussed below), BPA withdrew its disputed Section 7(b)(2) Legal Interpretation and Implementation Methodology.[47] BPA is contractually obligated to commence a process prior to FY 2029, and issue a record of decision on "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.[48] BPA plans to commence a separate process later this year to address the Section 7(b)(2) rate test Legal Interpretation and Implementation Methodology.

2.4 REP Implementation History

The REP has been a source of long-standing controversy among BPA's customers. IOUs and their stakeholders typically advocate for the REP to generate higher payments, leading to greater rate relief for their retail residential and farm consumers. Conversely, Public Power entities and their constituents generally seek lower REP payments to prevent increases in the cost of the program recovered in their power rates and to ensure they receive the protections guaranteed by the Northwest Power Act.

The first 20 years of implementation of the REP (1980-2000) saw multiple disputes over BPA's calculation and determination of the IOUs' ASC under the Average System Cost Methodology.[49] In the late 1990s, BPA and IOU REP participants attempted to avoid continued litigation by settling the REP through settled payments of REP benefits.[50] The

[45] *See* 16 U.S.C. § 839e(b)(1), (2), (3).
[46] 2025 REP Comprehensive Plan at 22.
[47] *Id.*
[48] Residential Exchange Program Settlement Agreement Proceeding, Administrator's Final Record of Decision, REP-12-A-02, Appendix A, Residential Exchange Program Settlement Agreement § 11.3 (July 26, 2011) ("2012 REP Settlement"), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2011-rod/rod-20110726-residential-exchange-program-settlement-agreement-proceeding-rep-12.pdf.
[49] 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. Utils. & Transp. Comm'n v. FERC*, 26 F.3d 935 (9th Cir. 1994); *CP Nat'l Corp. v. Bonneville Power Admin*., 928 F.2d 905 (9th Cir. 1991).
[50] 2025 REP Comprehensive Plan at 3.

early success of these agreements led to a broader effort to settle the REP in 2000 (2000 REP Settlement) for the 2001-2011 period. In the 2000 REP Settlement, BPA offered physical power and monetary payments to IOUs in return for a waiver of claims and of their participation in the traditional REP.[51] BPA classified the costs of the 2000 REP Settlement as a "settlement cost" and allocated these costs to Public Power customers' PF rates in their FY 2002-2006 power rates (the WP-02 rate proceeding). Notably, BPA did not perform the Section 7(b)(2) rate test when deciding to enter the 2000 REP Settlement or when recovering those costs from the PF rate charged to Public Power customers.

Public Power customers filed petitions in the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit or Court), challenging BPA's decision to agree to the 2000 REP Settlement (which included physical sales of power to the IOUs) and to allocate those costs to the PF rate without performing the Section 7(b)(2) rate test. In May 2007, the Ninth Circuit held the 2000 REP Settlement was unlawful and remanded BPA's WP-02 rates.[52] By the time the Court had ruled, BPA had already paid out close to $2.1 billion in settlement payments (inclusive of the value of physical power) to the IOUs.[53] The IOUs, in turn, distributed these funds and the value of the power 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 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 (2008 Residential Purchase and Sale Agreement (2008 RPSA)) and revise the ASC Methodology (2008 ASC Methodology). 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 the IOUs by offsetting future REP payments. BPA explained its reasoning in a 706-page decision document, the WP-07 Supplemental Record of Decision (WP-07S ROD).[54] IOUs, Public Power, and many other interested parties challenged BPA's WP-07S ROD and related decisions in court, with the result that at one point 56 petitions for review were pending before the Ninth Circuit in four consolidated cases.[55]

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[51] *Id.*

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

[53] 2025 REP Comprehensive Plan at 4.

[54] *See* 2007 Supplemental Wholesale Power Rate Case, Administrator's Final Record of Decision, WP-07-A-05, (Sept. 2008) ("WP-07S ROD"), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2008-rod/rod-20080922-2007-supplemental-wholesale-power-rate-case-final-rod.zip.

[55] 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 8-15 (July 26, 2011) ("REP-12 ROD"), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2011-rod/rod-20110726-residential-exchange-program-settlement-agreement-proceeding-rep-12.pdf.

2.5 2012 REP Settlement

The prospect of endless litigation over the REP led many representatives of Public Power customers and IOUs to pause their litigation efforts and participate in mediation of the REP disputes. In 2011, a settlement (2012 REP Settlement)[56] was reached between Public Power and IOU representatives. Under the 2012 REP Settlement, Public Power agreed to pay in their power rates the cost of a fixed schedule of REP payments to IOU participants until September 30, 2028. This fixed schedule included a reduction of REP benefits to account for refunds owed to Public Power customers for past overpayments. To ensure the 2012 REP Settlement was lawful, BPA evaluated the 2012 REP Settlement in a Section 7(i) proceeding for compliance with, among other provisions, the Section 7(b)(2) rate test. BPA concluded that the 2012 REP Settlement passed all statutory requirements and 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).[57]

A single challenge was made to the REP-12 ROD and 2012 REP Settlement in the Ninth Circuit. In 2013, the Court affirmed the Administrator's decision to adopt the 2012 REP Settlement and the REP-12 ROD.[58]

The 2012 REP Settlement expires on September 30, 2028. 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."[59] Instead, BPA "withdrew" its decisions regarding the REP from the WP-07 Supplemental ROD and related decisions, and replaced those decisions with the outcome provided in the 2012 REP Settlement and accompanying REP-12 ROD.[60] The 2012 REP Settlement expressly reserved all parties' rights and positions.[61] It also expressly stated that the terms of the settlement were neither precedential nor an admission of any parties' position on any issue.[62] With the expiration of the 2012 REP Settlement in 2028, BPA must be prepared for a return to the traditional REP for the post-2028 period.

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[56] The REP settlement affected rates beginning in FY 2012, and thus, is referred to as the 2012 REP Settlement.
[57] *See* REP-12 ROD at 410-17.
[58] *APAC*, 733 F.3d 939 (9th Cir. 2013).
[59] REP-12 ROD at 29.
[60] *Id.* ("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).").
[61] 2012 REP Settlement § 11.
[62] *Id.* § 11.2:

> No Precedential or Evidentiary Effect. Neither this Settlement Agreement nor its performance will (i) constitute any Party's agreement to any underlying principle or statutory interpretation in any context, (ii) constitute any Party's agreement to any methodology other than for purposes of implementing this Settlement Agreement in accordance with its terms for the Payment Period, or (iii) serve as procedural or substantive precedent regarding any matter in any context other than BPA proceedings to implement the terms of this Settlement Agreement.

2.6 Preparing for the Expiration of the 2012 REP Settlement: The Provider of Choice Concept Paper's REP Settlement Phase and Traditional REP Preparation Phase

On July 14, 2022, BPA issued its Provider of Choice Concept Paper in which BPA "officially launche[d] the policy development process" to describe and define the principles, goals, policies, and components of its post-2028 power sales contracts.[63] 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."[64]

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 toward a structured settlement of the REP . . . ."[65] 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."[66] The 2012 REP Settlement took almost four years of constant work and negotiation to achieve.[67] 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 sub-phase; 2) REP Contract Negotiation sub-phase; and 3) an REP Settlement Evaluation Process and Decision phase.[68]

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."[69] The Traditional REP Preparation Phase would begin the earlier of the end of settlement negotiations or the summer of 2025.[70] 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 implementation of the REP.[71]

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63 Bonneville Power Administration, Provider of Choice Concept Paper at 1 (July 14, 2022) ("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.
64 *Id.* at 59.
65 *Id*.
66 *Id.*
67 2025 REP Comprehensive Plan at 6.
68 POC Concept Paper at 59-60.
69 *Id.* at 61.
70 *Id.*
71 *Id.*

2.6.1 REP Settlement Phase – Phase 1

The REP Dry Run and Preparation sub-phase commenced in late summer 2022.[72] This phase began with general education workshops on the REP, its implementation, and an overview of the areas of dispute.[73] 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)) reflecting positions IOU and Public Power customers had taken in the REP-12 ROD and administrative record.[74] BPA also ran scenarios provided by the IOUs and Public Power customers based on their current "best case" scenario assumptions. These dry runs provided "a working educational model from which regional stakeholders may be able to familiarize themselves with, and get a sense of scale for, the various assumptions and factors that affect the REP benefits levels."[75] BPA completed its dry run analysis and the identification of its primary scenarios on May 23, 2023.[76]

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 Power customers and IOUs prepared settlement principles and perspectives on the REP.[77] On September 21, 2023, BPA issued a letter to the region, noting that, based on comments to date, BPA believed "additional REP settlement discussions would be best served if respective stakeholder representatives could meet outside of a BPA-hosted workshop environment."[78] Further BPA-sponsored workshops on REP negotiations would not be scheduled, but BPA encouraged IOU and Public Power 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

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[72] *See* Letter To Customers interested in Post-2028 Residential Exchange Program (Aug. 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.

[73] *See* Post-2028 Residential Exchange Program Workshop presentation (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; Post-2028 Residential Exchange Program Workshop presentation (Oct. 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.

[74] *See* Post-2028 Residential Exchange Program Workshop presentation (Feb. 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.

[75] POC Concept Paper at 59.

[76] *See* Post-2028 Residential Exchange Program Workshop presentation (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.

[77] *See* Post-2028 Residential Exchange Program Workshop presentation (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.

[78] *See* Letter to Regional Stakeholders Participating in the Post-2028 Residential Exchange Program Process (Sept. 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.

main scenarios developed from the Dry Run and Preparation sub-phase. These results were presented at a public workshop on January 23, 2024.[79]

Discussions between Public Power customers and IOU representatives continued throughout 2024 and into early 2025. During the discussions, representatives from both Public Power and IOU interest groups informed BPA of the status of negotiations. Ultimately, a settlement was not reached among the respective parties.[80]

2.6.2 Traditional REP Preparation Phase – Phase 2

On May 12, 2025, representatives from the IOUs requested BPA offer them a Residential Purchase and Sale Agreement for the post-2028 period by June 30, 2025.[81] BPA responded in a letter dated June 17, 2025, noting that, given the lack of progress on settlement of the REP, BPA would be issuing a "comprehensive plan for developing the applicable components of the traditional REP for the post-2028 period," including a public process to develop the post-2028 RPSA terms.[82]

Thereafter, on July 17, 2025, BPA issued the *Post-2028 Residential Exchange Program Comprehensive Plan* (*2025 REP Comprehensive Plan*).[83] In the *2025 REP Comprehensive Plan*, BPA explained that "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."[84] To that end, BPA outlined in the *2025 REP Comprehensive Plan* the "processes that BPA expects to engage in to prepare for REP implementation following expiration of the current settlement."[85] Specifically, these processes included: 1) the Residential Purchase and Sale Agreement process (2026 RPSA process); 2) ASC Methodology consultation process (2026 ASCM process); and 3) the Section 7(b)(2) Methodology/Legal Interpretation process.[86] The *2025 REP Comprehensive Plan* outlined the essential features of each of these processes, the expected products of those processes, and how those products would inform BPA's implementation of the REP.[87] Given the short timeframe for a contract in the IOUs' May 12, 2025 request, BPA also included two preliminary timelines for each of the processes, with both an expedited process and a longer process.[88]

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[79] *See* Post-2028 Residential Exchange Program Workshop presentation (Jan. 23, 2024), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/012324-Post-2028-REP-Customer-Workshop-Updated-01242024.pdf.
[80] 2025 REP Comprehensive Plan at 7.
[81] *See generally* IOU Letter Requesting RPSA at 1-2.
[82] *See* BPA Response to IOU Letter at 1 (June 17, 2025) (on file with author).
[83] *See generally* 2025 REP Comprehensive Plan at 1-24.
[84] *Id.* at 10.
[85] *Id.* at 1.
[86] *Id.* at 10.
[87] *Id.* at 11-23.
[88] *Id.*; *see also id.* at 24 (showing alternative timelines for the three processes).

After issuing the *2025 REP Comprehensive Plan*, BPA held a public workshop on July 28, 2025, to discuss the timelines for the three REP processes.[89] BPA requested comments on the REP processes by August 7, 2025.[90] Comments were received from the representatives of Public Power,[91] the IOUs,[92] and the Oregon Public Utilities Commission (OPUC).[93] The IOUs and Public Power supported the longer REP process. The OPUC suggested that BPA delay its processes given the OPUC's workload on other matters. On August 19, 2025, BPA issued a letter stating its intent to use the longer timeline for the REP processes, including a detailed schedule for the RPSA and ASCM processes.[94]

2.7 Procedural History of the 2026 ASCM Consultation Process

Section 5(c)(7) of the Northwest Power Act requires the BPA Administrator to develop a "methodology" for determining the "average system cost" for "electric power sold to the Administrator" under Section 5(c).[95] That methodology must be developed in consultation with "the [Northwest Power and Conservation] Council, the Administrator's customers, and appropriate State regulatory bodies in the region."[96]

The 2026 ASC Methodology consultation process (2026 ASCM process) was comprised of both public workshops with customers and consultation meetings with individual stakeholders. Public workshops were held on October 23, 2025,[97] December 3, 2025,[98]

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[89] *See* Post-2028 REP Comprehensive Plan Paper Clarification Workshop presentation (July 28, 2025) ("Post-2028 Comprehensive Plan Workshop PPT"), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/rep-comprehensive-plan-clarification-workshop.pdf.
[90] *Id.* at 8.
[91] Email from Northwest Requirements Utilities re: Post-Comprehensive Plan (Aug. 7, 2025) (on file with author); Western Public Agencies Group Response to REP Timelines (Aug. 5, 2025) (on file with author); Public Power Council Response to REP Timelines (Aug. 6, 2025) (on file with author).
[92] IOU Joint Comment on Post-2028 Residential Exchange Program Comprehensive Plan (Aug. 7, 2025) ("IOU Joint Comments on REP Comprehensive Plan") (on file with author).
[93] Oregon Public Utilities Commission Response to Post-2028 REP Process (Aug. 7, 2025) (on file with author).
[94] *See* Tech Forum, Bonneville Power Administration, Letter to Regional Parties Engaged in Post-2028 Residential Exchange Program Public Process (Aug. 19, 2025); BPA Letter to Region Regarding Post-2028 REP Process Timelines for Residential Purchase and Sale Agreement and Average System Cost Methodology, Attachment 1 (Aug. 19, 2025) ("BPA Letter to Region Regarding Post-2028 REP Timelines"), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/08182025-bpa-response-letter-rpsa-ascm-timeline.pdf.
[95] 16 U.S.C. § 839c(c)(7).
[96] *Id.*
[97] ASCM Workshop 1, Oct. 23, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/phase-2-post-2028-rep-ascm-workshop-20251023.pdf.
[98] ASCM Workshop 2, Dec. 3, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20251203-phase-2-post-2028-rep-ascm-workshop.pdf.

December 16, 2025,[99] January 27, 2026,[100] February 13, 2026,[101] April 15, 2026, and July 31, 2026.[102] All customer groups and representatives of the Council, state bodies, and various other interests were invited and encouraged to participate in these workshops. Many provided comments through these processes, which BPA Staff addressed, as appropriate.[103] In addition to public workshops, BPA Staff also met individually with state regulatory bodies and the Council to receive feedback and input on the initial revisions to the ASCM.[104] At these meetings, BPA identified its proposed revisions to various components of the ASCM for review by consulted parties.

Following initial feedback from stakeholders, BPA compiled its proposed revisions to the ASCM into a single document and posted it as the preliminary draft 2026 ASCM for informal comment on December 10, 2025.[105] On December 16, 2025, BPA posted the preliminary Appendix 1 and ASC Forecast Model for stakeholders to inspect.[106] BPA also held a workshop on December 16, 2025, to discuss and receive feedback on the preliminary draft 2026 ASCM.[107] Separately, BPA Staff met individually with the Council and all state regulatory bodies to receive feedback on the preliminary draft 2026 ASCM.[108] Initial

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99 ASCM Workshop 3, Dec. 16, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20251216-phase-2-post-2028-rep-ascm-workshop-3.pdf.

100 *See* ASCM Workshop 4, Jan. 27, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260127-post-2028-rep-ascm-informal-comments-workshop.pdf.

101 *See* ASCM Workshop 5, Feb. 13, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260213-post2028-rep-ascm-incremental-comments-workshop.pdf.

102 *See* ASCM Workshop 6, April 15, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260415-post-2028-rep-ascm-formal-comments-workshop.pdf.

103 *See e.g.,* Public Power Comments on ASC Workshop 1, Nov. 25, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/public-power-comments-on-asc-workshop-1.pdf; BPA Staff Response to Public Power Comments on ASCM Workshop 1, Dec. 10, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/bpa-staff-response-to-public-power-comments-ascm-workshop-1.docx; BPA Staff Clarification to Draft 2026 ASCM, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-bpa-staff-clarification-to-draft-2026-ascm.docx.

104 *See* BPA Letter to Northwest Power and Conservation Planning Council, Sep. 15, 2025 (on file with author); BPA 2026 ASCM Development Presentation to NPCC, Sep. 29, 2025 (on file with author); BPA, 2026 ASCM Development Presentation to OPUC, Oct. 10, 2025 (on file with author); BPA 2026 ASCM Development Presentation to IPUC, Oct. 14, 2025 (on file with author); Letter from BPA to Idaho PUC, Oct. 16, 2025 (on file with author); Letter from BPA to Montana PUC, Oct. 16, 2025 (on file with author); Letter from BPA to Oregon PUC, Oct. 16, 2025 (on file with author); Letter from BPA to Washington Utilities and Transportation Commission, Oct. 16, 2025 (on file with author); BPA 2026 ASCM Development Presentation to WUTC, Oct. 21, 2025 (on file with author); BPA 2026 ASCM Development Presentation to MT PSC, Oct. 21, 2025 (on file with author).

105 *See* Preliminary Draft 2026 ASCM, clean version, Dec. 10, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2026-ascm-preliminary-draft-clean.doc.

106 *See* Preliminary Draft 2026 Appendix 1, Dec. 16, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2026-ascm-appendix-1-draft.xlsx; *see also* Preliminary Draft 2026 ASC Forecast Model, Dec. 16, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2026-ascm-forecast-model-draft.xlsx.

107 *See* ASCM Workshop 3, Dec. 16, 2025.

108 *See* BPA 2026 ASCM Development Presentation to OPUC, Jan. 13, 2026 (on file with author); BPA 2026

comments on the preliminary draft 2026 ASCM were due January 21, 2026. BPA received comments from five commenters on the preliminary draft 2026 ASCM.[109] In view of these comments, BPA held another workshop on January 27, 2026, to discuss the comments and propose additional revisions to the preliminary draft 2026 ASCM.[110] On February 3, 2026, BPA posted another draft of the ASCM, calling it the "incremental draft 2026 ASCM."[111] Comments on the incremental draft 2026 ASCM were due February 10, 2026. Five parties filed comments by the deadline.[112] BPA held another workshop on February 13, 2026, to discuss the parties' comments and the proposed 2026 ASCM.[113] On February 20, 2026, BPA posted the draft 2026 ASCM and Appendix 1 for formal comment.[114] BPA Staff also issued a document clarifying the revisions made in the draft 2026 ASCM, as well as a spreadsheet that provided historical data regarding the treatment of Account 925.[115]

ASCM Development Presentation to OPUC, Jan. 15, 2026 (on file with author); BPA 2026 ASCM Development Presentation to NPCC, Jan. 21, 2026 (on file with author); BPA 2026 ASCM Development Presentation to IPUC, Jan. 22, 2026 (on file with author); BPA 2026 ASCM Development Presentation to WUTC, Jan. 28, 2026 (on file with author); BPA 2026 ASCM Development Presentation to MT PSC, Jan. 29, 2026 (on file with author).

[109] *See* AWEC Comments on Preliminary ASCM Draft, Jan. 21, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260123-AWEC-Comments-on-Preliminary-ASCM-Draft.pdf; IOU Comments on Preliminary ASCM Draft, Jan. 21, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260123-IOU-Comments-on-Preliminary-ASCM-Draft.pdf; NWPCC Comments on Preliminary ASCM Draft, Jan. 21, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260123-NWPCC-Comments-on-Preliminary-ASCM-Draft.pdf; Public Power Comments on Preliminary ASCM Draft, Jan. 21, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260123-Public-Power-Comments-on-Preliminary-ASCM-Draft.docx; WUTC Comments on Preliminary ASCM Draft, Jan. 21, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260123-WUTC-Comments-on-Preliminary-ASCM-Draft.pdf.

[110] *See* ASCM Workshop 4, Jan. 27, 2026.

[111] *See* Incremental Draft 2026 ASCM, Feb. 3, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/incremental-draft-average-system-cost-methodology.doc.

[112] *See* AWEC Comments on Incremental ASCM, Feb. 10, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/awec-comments-on-incremental-ascm-draft.pdf; COU Comments on Incremental ASCM, Feb. 10, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/cou-comments-on-incremental-ascm-draft.pdf; IOU Comments on Incremental ASCM, Feb. 10, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/iou-comments-on-incremental-ascm-draft.pdf; NWPCC Comments on Incremental ASCM, Feb. 10, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/nwpcc-comments-on-incremental-ascm-draft.pdf; WUTC Comments on Incremental ASCM, Feb. 10, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/wutc-comments-on-incremental-ascm-draft.docx.

[113] *See* ASCM Workshop 5, Feb. 13, 2026.

[114] *See* 2026 ASCM Draft for Formal Comment, Clean, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-2026-ascm-draft-for-formal-comment-clean.doc; 2026 ASCM Draft Appendix 1, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-appendix-1-template.xlsx.

[115] *See* BPA Staff Clarification to Draft 2026 ASCM, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-bpa-staff-clarification-to-

Comments on the draft 2026 ASCM and Appendix 1 were due April 2, 2026. BPA received four comments by the deadline.[116] In view of those comments, and some additional clarifications BPA Staff wanted to make to the 2026 ASCM, BPA held another workshop on April 15, 2026.[117] At that workshop, BPA Staff presented a number of clarifications they intended to add to the 2026 ASCM to reflect updated FERC Account information.[118] Because of FERC's recent account changes, BPA Staff also proposed to clarify certain ASCM language to allow BPA to reflect future adjustments to FERC accounts.[119] Finally, BPA Staff provided a high-level overview of the comments, which included a number of new topics not previously discussed during the consultation process.[120] Given the number of new issues, and in consideration of the clarifications it intended to make, BPA modified the consultation schedule to add another draft of the ASCM, inclusive of a draft ROD, followed by another opportunity for comment. Under this revised schedule, BPA proposed issuing the draft ROD on May 15, 2026, with formal comments due by May 29, 2026, and the final ROD scheduled for release on June 26, 2026.[121]

Following the April 15, 2026, workshop, then BPA Administrator John Hairston retired from federal service in May 2026. Travis Kavulla was sworn in as his successor on June 29, 2026.[122] With the arrival of a new Administrator, BPA Staff extended the ASCM consultation schedule, adding another workshop and further opportunities to provide public feedback. BPA held this additional workshop on July 31, 2026, to discuss further updates to the 2026 ASCM, with interim feedback due by August 14, 2026.[123] Three parties filed feedback.[124] After reviewing this feedback, BPA issued the draft ROD on September

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draft-2026-ascm.docx; Historical Percentages of Account 925 Since 2006, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/202602-20-ascm-925-of-total-production-costs.xlsx.

[116] Comments were submitted by the IOUs, AWEC, Public Power customers, and the WUTC. All comments are available at https://publiccomments.bpa.gov/Category/CategoryDetails?CategoryId=546. For purposes of this Draft ROD, comments are identified by the month filed. Thus, IOU comments submitted on April 2 are identified as IOU Comments (April).

[117] *See* ASCM Workshop 6, April 15, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260415-post-2028-rep-ascm-formal-comments-workshop.pdf.

[118] *Id.* at 5-14.

[119] *Id.* at 16.

[120] *See id.* at 18-20.

[121] *Id.* at 23.

[122] *See* BPA Website, Executives & Structure, Travis Kavulla, June 29, 2026, *available at* https://www.bpa.gov/about/who-we-are/executives/travis-kavulla.

[123] *See* ASCM Workshop 7, July 31, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/20260731-post-2028-rep-ascm-workshop.pdf.

[124] *See* COU Interim Feedback on July 31, 2026 Workshop, Aug. 14, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/cou-interim-feedback-july-31-2026-workshop.pdf; IOU Interim Feedback on July 31, 2026 Workshop, Aug. 14, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/iou-ascm-interim-feedback-july-31-2026-workshop.pdf; WUTC Interim Feedback on July 31, 2026 Workshop, Aug. 14, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/wutc-interim-feedback-july-31-2026-workshop.pdf.

11, 2026. Parties have until October 16, 2026, to submit formal comments on the draft ROD's proposed positions and decisions.

2.8 Issues

Issue 2.8.1

Whether BPA properly consulted with regional parties as required by Section 5(c)(7) when developing the 2026 ASCM.

BPA Staff's Proposal

BPA's consultation process offered regional parties appropriate opportunities for comment and feedback on BPA's proposed revisions to the 2026 ASCM.

Parties' Positions

The IOUs argue BPA has not engaged in a "meaningful, cooperative consultation that the NWPA requires."[125] The IOUs contend that Congress required a consultation process in order to allow BPA customers to share "information, concerns, and expertise" to shape the decision-making process from its earliest stages.[126] The IOUs refer to the ASCM consultation as "perfunctory at best" and falling short of the requirements of a consultation as required by the Northwest Power Act.[127] The IOUs claim that compared to previous ASCM consultations, the 2026 ASCM consultation has been inconsistent and inadequate.[128] The IOUs contend that BPA's failure to provide them an opportunity to respond to BPA's justification for its changes to the ASCM, outside of "workshop presentations," is "per se arbitrary and capricious."[129]

Evaluation of Positions

Section 5(c)(7) of the Northwest Power Act directs the BPA Administrator to develop a methodology for calculating the average system cost for "electric power sold to the Administrator under this subsection" in "consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region."[130] The average system cost of resources "shall be determined by the Administrator" on the basis of this methodology.[131] The Act neither defines the term "consultation" nor prescribes any particular procedures under which to conduct this consultation. The normal usage of the term "consultation" is the "act of consulting or conferring."[132] The term "consult" means "to ask the advice or opinion of . . . ."[133] Taken together, the statutory language is clear that the Administrator has discretion to design the consultation process in a manner BPA

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[125] IOU Comments (April) at 14.
[126] *Id.*
[127] *Id.* at 15.
[128] *Id.* at 16.
[129] *Id.*
[130] 16 U.S.C. § 839c(c)(7).
[131] *Id.*
[132] Merriam Webster Dictionary, https://www.merriam-webster.com/dictionary/consultation (last visited June 30, 2026).
[133] *Id.*, https://www.merriam-webster.com/dictionary/consult.

determines provides a reasonable opportunity to solicit and receive "advice" or "opinions" from the respective statutorily identified groups. This discretion also means BPA can tailor the process to the respective needs of the particular ASCM, and the process used in one ASCM need not be repeated in another.

The IOUs claim that BPA has not engaged in a "meaningful, cooperative consultation that the NWPA requires."[134] The IOUs contend that Congress required a consultation process in order to allow BPA customers to share "information, concerns, and expertise" to shape the decision-making process from its earliest stages.[135] The IOUs argue that BPA's engagement has been "perfunctory at best" and "falls short of the meaningful, cooperative consultation required by statute."[136]

BPA's approach for consulting with required entities regarding the 2026 ASCM is described above in section 2.7 of this ROD, and consisted of a series of public workshops along with private meetings with the various constituencies held over ten months (and this process is ongoing with this draft ROD).[137] BPA will not recount all the meetings here, but in short, BPA held 17 consultation meetings with Public Power customers, IOUs, the Council, and state regulatory bodies.[138] Each of these consultations provided opportunities for those present to provide their "advice" and "opinion" on various aspects of the ASCM, drafts of which were provided at each meeting. Apart from these meetings, BPA provided numerous opportunities for these entities to submit informal comments, to comment on BPA Staff changes, to suggest additional changes, and to engage with BPA Staff on the terms of the 2026 ASCM.[139] BPA was responsive to this feedback, and posted six successive versions of the ASCM, each of which was adjusted in response to stakeholder comments (preliminary

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[134] IOU Comments (April) at 14.
[135] *Id.* at 14-15, *citing* Cong. Rec. S14691 (daily ed. Nov. 19, 1980) (statement of Sen. Henry Jackson).
[136] IOU Comments (April) at 15.
[137] *See* section 2.7 of this ROD.
[138] As noted in section 2.7 of this ROD, BPA met individually with the state commissions and the Council, and then held public workshops with its customers. Individual meetings with the commissions were deemed appropriate as many of these entities do not normally participate in BPA workshops and this approach was consistent with BPA's past outreach on other ASCM consultations. BPA chose public meetings with its customers because this followed the normal cadence of how BPA interacted with these constituents, and it would have been impractical to meet with these customers individually, as BPA has over 130 power customers.
[139] *See, e.g.,* ASCM Workshop 1, at 71, Oct. 23, 2025 (noting that how to submit written comments to BPA on ASCM); ASCM Workshop 2, at 51, Dec. 3, 2025 (same); ASCM Workshop 3, at 41, Dec. 16, 2025 (same); ASCM Workshop 4, at 26, Jan. 27, 2026 (same).

draft,[140] incremental draft,[141] draft for formal comment,[142] post-comment initial draft,[143] post-comment draft[144]).

Even with this extensive engagement, the IOUs contend BPA's consultation is flawed because BPA did not provide "substantive, written explanation or justification for its evolving ASCM changes beyond the workshop presentations."[145] However, that level of formal iterative response lacks precedent; BPA did not engage with participants in that manner during the 1981, 1984, or 2008 ASCM consultations. While the IOUs cite the 2008 draft ROD as an example, that document was issued only at the end of the process after formal comments were received.[146] Furthermore, the Northwest Power Act does not require a draft ROD, as evidenced by the 1981 and 1984 consultations, which proceeded without one.

Additionally, when Congress intends for BPA to engage in more formal interactions with its customers, or to achieve a negotiated outcome, it explicitly provides those requirements. For example, Section 7(i) mandates formal rate processes,[147] while Section 7(l) requires BPA to work with counterparties to achieve "negotiated" rates.[148] By contrast, Section 5(c)(7) lacks any such formalities. BPA is to "consult" with—take advice or opinions—on the terms of the ASCM, and that it has done.

Nonetheless, as noted above, BPA concludes that a draft ROD on the 2026 ASCM, though discretionary, is reasonable and appropriate because of the additional clarifications BPA Staff intends to make to the ASCM and the number of new issues raised by parties in their formal comments. This document and the additional opportunity to review also addresses the IOUs' process concerns.

<u>Draft Decision</u>

BPA properly consulted with regional parties as required by Section 5(c)(7) when developing the 2026 ASCM. BPA will exercise its discretion to issue a draft Record of Decision for public review and comment before issuing a final decision.

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[140] *See* Preliminary Draft 2026 ASCM, clean version, Dec. 10, 2025, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2026-ascm-preliminary-draft-clean.doc.
[141] *See* Incremental Draft 2026 ASCM, Feb. 3, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/incremental-draft-average-system-cost-methodology.doc.
[142] *See* 2026 ASCM Draft for Formal Comment, Clean, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-2026-ascm-draft-for-formal-comment-clean.doc; 2026 ASCM Draft Appendix 1, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-appendix-1-template.xlsx.
[143] 2026 ASCM Redlines for Workshop 7, July 31, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/ascm-workshop-redlines-20260731.docx.
[144] *See* draft 2026 ASCM (attached).
[145] IOU Comments (April) at 16.
[146] *See* 2008 ASCM ROD at 16.
[147] 16 U.S.C. § 839e(i).
[148] *Id.*

3.0 2026 AVERAGE SYSTEM COST METHODOLOGY PRIMARY ELEMENTS AND STRUCTURE

3.1 Statutory Guidance

Section 5(c)(1) mandates that, for purposes of the REP energy-neutral purchase and sale transaction, BPA purchases power from an exchanging utility based on that utility's "average system cost of . . . resources . . . ."[149] The Northwest Power Act does not define the term "average system cost." Furthermore, "average system cost" is employed in three distinct ways within Section 5(c): Section 5(c)(1) refers to it as the "average system cost of that utility's resources in each year," Section 5(c)(4) labels it the "average system cost of power," and Section 5(c)(7) identifies it as the "'average system cost' for electric power sold to the Administrator under this subsection."

Rather than explicitly defining "average system cost" for each usage, Congress directed the BPA Administrator to develop a methodology for determining a utility's average system cost for its resources, power, or electric power. Specifically, the statute states:

> The "average system cost" for electric power sold to the Administrator under this subsection shall be determined by the Administrator on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission.[150]

The only other explicit Congressional directive regarding the features of the ASCM is the exclusion of certain resource costs. These include:

> (A) the cost of additional resources in an amount sufficient to serve any new large single load of the utility;
>
> (B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and
>
> (C) any costs of any generating facility which is terminated prior to initial commercial operation.[151]

This list of exclusions from ASC is not exhaustive. The Ninth Circuit has determined that the Act "assigned to the BPA Administrator in rate making proceedings to devise a 'methodology' for determining costs."[152] Congress' use of the consultation process and

[149] 16 U.S.C. § 839c(c)(1).
[150] 16 U.S.C. § 839c(c)(7).
[151] 16 U.S.C. § 839c(c)(7)(A)-(C).
[152] *PacifiCorp*, 795 F.2d at 822. The court's reference to "rate making proceedings" was likely in reference to the ASC consultation process, which results in the ASC Methodology being filed with FERC. While this process results in a filing with FERC, there is no requirement that BPA conduct a "rate making proceeding" under section 7(i) to adopt the ASC Methodology and, indeed, the Court's citation is to Section 5(c)(7), rather than Section 7(i).

review by FERC also indicated "that Congress was aware that difficult judgments needed to be made," meaning that "[t]he statutory scheme militates against . . . [a] theory that Congress intended all costs to be included except those specifically excluded in section 5(c)(7)."[153]

Collectively, this context establishes that the primary aim of the ASCM is to calculate the average cost a utility incurs to produce "electric power" from its "resources." This average cost is then compared to BPA's power cost (the PF Exchange rate) to determine the "cost benefit" mentioned in section 5(c)(3), which is the overall purpose of the REP.[154] Given this purpose, BPA must design the ASCM so that a utility's ASC accurately reflects its costs of electric power resources. Additionally, the types of resource and electricity costs included in the ASC calculations must bear some relationship to those costs BPA includes in its own power rates, ensuring an appropriate comparison for calculating the statutory "cost benefit."[155]

After developing the ASCM, BPA must file it with FERC for its "review and approval."[156] The ASCM is a BPA rule codified in Federal Energy Regulatory Commission (FERC) regulations.[157] FERC has recognized the unique purpose served by the ASCM, describing the ASCM as "a mechanism for calculating a subsidy" and "not for establishing a traditional cost of purchased power."[158]

3.2 Prior ASC Methodologies

BPA has developed three ASC Methodologies over the last 40 years, the latest of which was developed in 2008. Each is described in the following section.

3.2.1 1981 ASC Methodology

The first ASCM was developed in 1981 following the signing of the Northwest Power Act into law in 1980. The 1981 Average System Cost Methodology (1981 ASCM) was developed in consultation with interested parties through a series of working group meetings attended by representatives of IOUs, Public Power customers, direct service industries (DSIs), the region's State regulatory agencies, members of the public, and BPA Staff. BPA published its final 1981 ASCM on August 26, 1981, in a Record of Decision

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[153] *Id.*

[154] 16 U.S.C. § 839c(c)(3); *see also* 2026 RPSA ROD at 46-49.

[155] There will, of course, be some obvious differences between BPA's rates (which are cost-only based) and a for-profit utility's rates. For example, a utility earns a return on equity (ROE) to compensate shareholders for their investment. While BPA's rates do not include a ROE, they do incorporate BPA's own cost of capital, primarily through debt financing. Therefore, although the form of these costs differs, they are comparable types of expenses that each entity incurs to finance its utility infrastructure.

[156] 16 U.S.C. § 839c(c)(7) ("Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission.").

[157] *See Cent. Elec. Coop. v. Bonneville Power Admin.*, 835 F.2d 199, 204 (9th Cir. 1987). As described above, only the ASC calculation portion of the ASCM is codified in FERC regulations. *See* 18 C.F.R. § 301.1-301.7. BPA's ASC Rules of Procedure are not included in the FERC regulation.

[158] *Methodology for Sales of Elec. Power to the Bonneville Power Admin.*, 30 FERC ¶ 61,108, 61,196 (1985).

("1981 ASCM ROD").[159] That decision was based on a general agreement among the parties that had resolved nearly all issues raised in the consultation proceeding.[160] FERC granted interim approval of the 1981 ASCM on October 14, 1981,[161] and final approval on October 17, 1983.[162]

Under the 1981 ASCM, each participating utility was required to submit to BPA the utility's ASC data on a form, called an Appendix 1,[163] for each jurisdiction in which the utility intended to exchange power with BPA. The data for the Appendix 1 came from retail rate filings and orders. This approach to filling out the Appendix 1 was called the "jurisdictional costing approach"[164] because the information in the utility Appendix 1 filings was based on filings with, or rate orders from, state public utility commissions for each state jurisdiction the utility operated in.[165] Many utilities operated in multiple states, resulting in a multiplicity of ASC filings with BPA.[166] Every retail rate change requested by the participating utility would trigger a new Appendix 1 filing, and hence, a new ASC review process by BPA.[167] Between October 1981 and October 1983, BPA reviewed 63 ASC filings.[168]

The 1981 ASCM contained few exclusions from a utility's ASC beyond those expressly prescribed by the Northwest Power Act. This followed from a general consensus reached among parties and BPA regarding the methodology, which based the ASC calculation on "the costs allowed or established for retail ratemaking purposes . . . ."[169] Besides establishing the wholesale nature of the ASCM, and expressly excluding a utility's distribution-level costs, the 1981 ASCM ROD contains little discussion for the rationale behind the various costs included in the ASCs.[170]

3.2.2 1984 ASC Methodology

The 1981 ASCM relied heavily on state utility commission orders for data as required by the "jurisdictional costing approach" to calculating a utility's ASC. This created

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[159] *See* Administrator's Record of Decision, Average System Cost Methodology, Aug. 26, 1981 ("1981 ASCM ROD"), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/1981-ascm-rod.pdf.
[160] *See* 2008 ASCM ROD at 5.
[161] *Sales of Electric Power to the Bonneville Power Administration; Filing of Rate Schedules; Interim rule*, 46 Fed. Reg. 50,517 (Oct. 14, 1981) (corrected at *Filing of Rate Schedules; Correction*, 46 Fed. Reg. 55,952 (Nov. 13, 1981)).
[162] *Sales of Electric Power to Bonneville Power Administration, Methodology and Filing Requirements*, 48 Fed. Reg. 46,970 (Oct.17, 1983) ("Order No. 337").
[163] Appendix 1 refers to the appendix to the ASC Methodologies containing the form on which exchanging utilities report their cost of resources (known as "Contract System Cost") and other information required for the calculation of ASC.
[164] 1981 ASCM ROD at 11 (describing the "Jurisdictional Costing Approach.")
[165] 2008 ASCM ROD at 6.
[166] 1981 ASCM ROD at 11.
[167] 2008 ASCM ROD at 6.
[168] *Id.*
[169] 1981 ASCM ROD at 11.
[170] 1981 ASCM ROD at 7.

administrative challenges for BPA, as regulatory orders often lacked the specificity needed for ASC computation, requiring imputations.[171] A significant drawback was that state regulators focused on setting reasonable rates, and therefore, were not bound by the Northwest Power Act's requirements.[172] This could lead to higher retail rates, which, benefiting from REP payments, did not necessarily translate to higher bills for ratepayers, potentially reducing incentives for utilities to control costs. Concerns about abuses emerged, particularly regarding the inclusion of costs from terminated plants, which were expressly prohibited by the Northwest Power Act. BPA faced difficulties identifying and removing such costs due to unclear state regulatory rulings, highlighting the need for a revised methodology.[173]

These issues prompted BPA's DSI and public agency customers to request a consultation process to revise the 1981 ASCM.[174] In response, BPA initiated the 1984 ASCM consultation proceeding on October 7, 1983, and, after review and public comment, released a new proposed 1984 ASCM in May 1984, which was eventually approved by FERC.[175] This new methodology introduced a significantly more elaborate 210-day review process with specific timelines for challenges, BPA issue lists, multiple rounds of comments, and a formal discovery process.[176] It also brought substantive changes to cost allowances, including limitations on transmission plant costs, the exclusion of return on equity (especially after suspicions arose that public utility commissions were approving higher ROEs to compensate utilities for prohibited terminated plant costs), and the exclusion of federal income taxes from ASC calculations.

The 1984 ASCM faced opposition from IOUs and state commissions, leading to several lawsuits challenging its creation[177] and implementation.[178] These entities specifically contested BPA's decision to remove income taxes and use embedded long-term debt costs instead of return on equity in ASC calculations.

FERC approved the 1984 ASCM, deferring to BPA's discretion regarding tax and equity exclusions.[179] This approval was later affirmed by the Ninth Circuit Court of Appeals in

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[171] 2008 ASCM ROD at 6.
[172] *Id.* at 7.
[173] *Id.*
[174] *Id.* at 8.
[175] *See Methodology for Sales of Electric Power to Bonneville Power Administration; Notice of Proposed Interim Rule and Notice of Proposed* Rulemaking, 49 Fed. Reg. 24,146 (June 12, 1984) (requesting comments on whether to grant interim approval); *Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293 (Oct. 5, 1984) (final approval) ("Order No. 400").
[176] 2008 ASCM ROD at 8-9.
[177] *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*, 795 F.2d 816.
[178] *See, e.g., Portland Gen. Elec. Co.*, 29 FERC ¶ 61,044, (1984); *Idaho Power Co.,* 37 FERC ¶ 61,104 (1986); *Pacific Power & Light Co.*, 37 FERC ¶ 61,105 (1986); *Montana Power Co.*, 37 FERC ¶ 61,103 (1986); *Puget Sound Power & Light Co.*, 75 FERC ¶ 61,239 (1996); *see also Wash. Utils. & 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).
[179] *See* Order No. 400 at 39,296-97; *Methodology for Sales of Electric Power to the Bonneville Power Administration,* Order No. 400-A, 30 FERC ¶ 61,108, at 61,196 (Feb. 1, 1985) (denying rehearing).

PacifiCorp v. FERC.[180] The Court's ruling noted that while it upheld BPA's decisions in that instance, it did not permanently sanction these exclusions, emphasizing that the statute neither mandated nor prohibited such adjustments.[181] BPA's exclusions related to transmission were not addressed by the Court.

3.3 Current Methodology: 2008 ASC Methodology

3.3.1 Overview of 2008 ASC Methodology

As detailed in the previous section, the implementation of the 1984 ASCM was highly controversial. This led many utilities to settle their involvement in the REP throughout the 1990s.[182] After the Court's rulings in *PGE* and *Golden NW* overturned the 2000 REP Settlement and the WP-07 rates, discussed in section 2.4 of this ROD,[183] BPA initiated a new consultation process in August 2007 pursuant to Section 5(c)(7) of the Northwest Power Act to revise the 1984 ASCM and update its terms for modern implementation of the REP.[184] At the conclusion of this consultation process, BPA issued the 2008 ASCM in June 2008, introducing several significant changes.

The first general area of change was structural. The 1984 ASCM mandated that participating utilities file a new ASC with BPA for every retail rate change, initiating a 210-day review process.[185] This approach led to frequent processes, due to numerous participating utilities in multiple states. The constant changes to a utility's ASC also led to fluctuations in BPA's REP payments as updated ASCs often diverged from the ASCs BPA forecasted when setting rates. 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 toward a utility's FERC Form 1 as the source data for its ASC calculation.[186] This data source is uniform across the IOU utilities and facilitates easier administration for all parties. Use of the FERC Form 1 also allowed BPA to simplify the ASC review process to a single process conducted concurrent with BPA's general rate cases.

The second general area of change related to substantive cost inclusions. Given changes in the governance of utility ratemaking, and the unlikely reoccurrence of unlawful terminated plant being included in a utility's ROE, BPA allowed those costs back into ASC as a cost of an IOU's resources.[187] In addition, given certain policy considerations, BPA also revised its policy decision to limit transmission costs in ASC, and allowed a utility's transmission back

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[180] *PacifiCorp*, 795 F.2d 816.
[181] *Id.* at 823.
[182] *See supra* section 2.5 of this ROD.
[183] *Id.*
[184] *See* 2008 ASCM ROD at 14.
[185] *See id.* at 8-9.
[186] The FERC Form No. 1 is a comprehensive financial and operating report submitted to FERC by regulated utilities (IOUs) for electric rate regulation and financial audits. *See* https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-1-f-3-q-electric-historical-vfp-data.
[187] *See* 2008 ASCM ROD at 102-22.

into ASC.[188] FERC subsequently approved the 2008 ASCM.[189] No challenges to the 2008 ASCM were filed in the Court.

3.3.2 General Structure and Approach to Calculating a Utility's ASC of Resources under the 2008 ASCM

The 2008 ASCM is composed of two primary sections. The first section outlines the formulas and accounting rules used to determine the costs and loads included in a utility's cost of resources for electric power.[190] It is the only part reviewed by FERC and is incorporated into the Commission's regulations.[191] This section also includes the Appendix 1, the form used to calculate the ASC.

The second section is BPA's ASC Review Process Rules of Procedure (ASC Procedures).[192] These are rules that govern the process conducted by BPA to determine a utility's ASC. Once an ASC is determined by BPA through an ASC Report, the utility (if an IOU), files this ASC with FERC for its review for compliance with the ASCM.[193] The ASC Procedures are BPA rules, and thus, are not filed with FERC.[194]

Both components are described in greater detail below.

3.3.2.1 General Approach to Calculating a Utility's ASC of Resources.

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

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

Part I of the 2008 ASCM identifies the type of resource costs that qualify as "contract system costs" and the loads that qualify as the utility's "contract system load." The source of data for this information is the utility's FERC Form 1.

The FERC Form 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."[195] The FERC Form 1 follows FERC's Uniform System of Accounts.[196] The Uniform System of Accounts is comprised of a number of FERC "accounts"

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188 *Id.* at 125-42.
189 *See Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology,* 124 FERC ¶ 61,312 (Sep. 30, 2008) (interim approval); *Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology*, 74 Fed. Reg. 47,052 (Sep. 15, 2009) (final approval) ("Order No. 726").
190 *See* 2008 ASCM ROD, Attachment A, §§ II, IV, V, VII, VIII, Table 1, and Appendix 1 Endnotes.
191 The FERC regulation can be found at 18 C.F.R. § 301.1-7.
192 2008 ASCM ROD § III; Rules of Procedure for BPA's ASC Review Processes, *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.
193 *See* 18 C.F.R. § 35.30-31.
194 *See* Order No. 726 at P 37; *see also* Order No. 337 at 46,971.
195 *See* https://www.ferc.gov/industries-data/electric/resources/industry-forms/form-no-1-annual-report-major-electric-utility.
196 18 CFR Part 101, "Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act," *available at* https://www.ecfr.gov/current/title-18/chapter-

that cover certain specified categories of costs or credits. The costs or credits included in these accounts cover a historical period, typically the prior calendar year.

The 2008 ASCM mandates that utilities use FERC Form 1 data from the year preceding the applicable BPA rate period to calculate their ASC.[197] This data is entered into an Excel-based spreadsheet, known as an Appendix 1. The Appendix 1 categorizes (or functionalizes) the costs and credits from each FERC account in the FERC Form 1 into one or more of three cost categories: Production, Transmission, or Distribution/Other.[198] Under the 2008 ASCM, costs allocated to the Production and Transmission categories are included in the utility's ASC, while those for Distribution/Other are not.[199]

To identify the applicable cost category for FERC accounts, the 2008 ASCM uses functionalization "codes" for each line of the Appendix 1. For example, if a FERC account is assigned entirely to Production, it receives a functionalization code of 'P'. Some accounts are assigned to multiple categories, receiving a combined functionalization code like 'PTD'. In such cases, the costs in these accounts are divided among the Production, Transmission, and Distribution/Other cost categories based on a ratio of the relative size of the utility's plant for each. For instance, if a utility's total plant consists of 50% Production, 30% Transmission, and 20% Distribution, the PTD code would similarly functionalize costs in a manner consistent with the PTD allocation (50% to P, 30% to T, and 20% to D/Other).

3.3.2.1.1 *Base Period ASC*

Once a utility's Contract System Cost and Contract System Load is included in the Appendix 1, a "Base Period" ASC is determined.[200] This Base Period ASC reflects the utility's ASC based on historical FERC Form 1 data. This Base Period ASC is then adjusted using a forecast model to reflect the dollars and prices applicable during the current rate period (known as the Exchange Period).[201] This escalated ASC is called the Exchange Period ASC, and it is used to calculate the utility's payments under the REP.[202]

3.3.2.1.2 *Exchange Period ASC*

Since a utility's ASC of resources was based on a historical period, it did not inherently capture resource costs from additions or reductions that occurred outside that period. Recognizing this, the 2008 ASCM included provisions to account for changes in the utility's resource costs, service territories, and loads that took place outside the Base Period.[203] However, to avoid constant disruption for both BPA and the utility, the 2008 ASCM limited

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I/subchapter-C/part-101.

[197] *See* 18 C.F.R. § 301.2 (definition of Base Period).
[198] *See* 18 C.F.R. § 301, Table 1.
[199] *See* Order No. 726 at P 23.
[200] *Id.* at P 21.
[201] *Id.* at P 29-30.
[202] *See* 18 C.F.R. § 301.4.
[203] *See* 18 C.F.R. § 301.4(c).

changes to only those with a "material" impact on a utility's ASC.[204] If a change was not material, it would not be reflected in the utility's ASC for that Exchange Period. Instead, the new resource costs would be reflected in a future ASC when they appeared in the FERC Form 1 for the year in which the cost was actually incurred. If the change was material, the additional costs would be accounted for during the ASC review process, allowing the utility's ASC to change during the Exchange Period after providing evidence that the resource had become commercially operational. This approach represented a reasonable compromise between constantly updating ASCs with every new resource cost or retirement and fixing the utility's ASC for the entire exchange period without any changes.

3.3.2.2 Procedures and Process for Determining an ASC

Section III of the 2008 ASCM set forth the procedures for determining a utility's ASC. These procedures are referred to as BPA's Rules of Procedure for BPA's ASC Review Processes (ASC Procedures).[205] The ASC Procedures establish the timing deadlines for the ASC Review process, discovery protocols, issue lists, and other administrative tasks that enable BPA Staff to review the utility's ASC for compliance with the rules and terms of the ASCM. The ASC Procedures also include Confidentiality Rules to ensure parties provide and receive information on resources and loads, subject to restrictions on the use and dissemination of commercially sensitive data. The ASC Procedures also establish the process for preserving issues for review and appeal before the Administrator and, later, FERC.

As part of the ASC Procedures, the 2008 ASCM included the requirement that utilities file an Appendix 1 with ASC data on "off-years," meaning years in which BPA was not establishing a formal ASC for each utility. Submittal of ASC data in "off years" is referred to in the ASC Procedures as "informational ASC filings."[206] Informational ASC filings do not change a utility's ASC and, therefore, are not subject to BPA's formal ASC Procedures. Instead, informational ASC filings allow BPA Staff to track a utility's costs and credits in their FERC accounts, which allows BPA Staff to better identify anomalous costs and credits when reviewing the utility's actual ASC in a formal ASC review process.

3.3.3 2008 ASCM In Practice

The 2008 ASCM has proven to be a resilient and efficient methodology for calculating utility ASCs. No ASCs under the 2008 ASCM have been challenged at FERC or in Court, although this is likely due to the presence of the 2012 REP Settlement.[207] While the 2008

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[204] *Id.*

[205] The most current version of these procedures 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.

[206] 2008 ASC Procedures §§ 2.1.2, 3.

[207] Under the 2012 REP Settlement, total REP benefits were set for each year of the contract (*i.e.,* until September 30, 2028). The distribution of the fixed amount of REP benefits for each year is a function of the utility's ASC compared to a modified version of BPA's PF Exchange rate. Thus, utility's ASCs did not determine the total amount of REP benefits. Instead, utility's ASCs determined how much of the fixed amount

ASCM has performed well, it will be 20 years old at the time of the expiration of the 2012 REP Settlement in September of 2028. 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 is warranted. Additionally, certain cost categories that have historically been a small part of a utility's ASC have grown, and thus, require greater scrutiny and review in light of the statutory purpose of the Section 5(c)(1) exchange. Finally, BPA has taken a deeper look at the statutory basis of certain cost categories to ensure those remain valid and are supportable for inclusion in ASC as contemplated in the Northwest Power Act.

3.4 2026 ASC Methodology

3.4.1 Overview of Primary Elements of 2026 ASC Methodology

The 2026 ASCM largely mirrors the terms and provisions of the 2008 ASCM.

Structurally, the 2026 ASCM aligns with the 2008 ASCM: Part I of the 2026 ASCM outlines the methodology and forms for calculating a utility's ASC, while Part II contains BPA's ASC Procedures.

Procedurally, the 2026 ASCM largely maintains the existing rules and process from the previous ASC Procedures, with some additional clarifications and enhancements. The timing for formal ASC filings will continue to coincide with BPA rate proceedings, and utilities will still be required to submit informational ASCs.

Substantively, the 2026 ASCM also retains many features of the 2008 ASCM. Utilities will continue to use FERC Form 1 as the primary data source for ASC calculations. This information will be entered into an Appendix 1, which functionalizes the utility's costs into Production, Transmission, and Distribution categories. The 2026 ASCM will continue to calculate a Base Period ASC using historical FERC Form 1 data, escalate this ASC using the ASC Forecast Model, and then determine an Exchange Period ASC, which will be used to calculate the utility's REP payments. In *Issue 3.5.2* below, BPA addresses a suggestion that it remove costs from ASC disallowed by state regulators.

In most cases, the types of costs included in a utility's ASC have also not changed. However, for certain cost categories, BPA re-evaluated its rationale and past practices to determine if the treatment under the 2008 ASCM remained appropriate. As explained in the next section, this evaluation led to the removal of some costs from ASC, the requirement for additional documentation for others, and clarifications on how BPA intends to calculate certain costs going forward.

3.4.2 2026 ASCM: Primary Adjustments from 2008 ASC Methodology

In this section, BPA describes the primary adjustments adopted in the 2026 ASCM as compared to the 2008 ASCM. This section does not identify every change made, as these

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of REP benefits each utility received. Given that the total amount of REP payments was pre-determined and fixed, utilities (and Public Power customers) had little incentive to challenge a utility's ASC filing.

were discussed in the consultation workshops BPA held.[208] Additional details on specific changes will be described in the relevant section of this ROD.

3.4.2.1 Transmission Costs

One of the more significant changes in the 2026 ASCM is BPA's decision to return to a more limited inclusion of transmission costs in the calculation of a utility's ASC of electric power from its resources. Under the 2008 ASCM, all wholesale transmission costs of a utility were included in its ASC, including the costs of the utility's transmission plant. While not legally required, this inclusion was permitted as a matter of BPA policy.[209]

BPA re-evaluated this issue in the consultation process leading up to the 2026 ASCM. As discussed in *Issue 3.5.1*, BPA concludes that to properly implement the REP consistent with Congress's intent expressed in the text of the Northwest Power Act, the ASCM must limit its scope to the utility's cost of electric power from its resources. The costs of the utility's transmission system, which are not costs of producing electric power from the utility's resources, should therefore not be included in its ASC. This approach aligns with the statutory text and purpose of the REP.

3.4.2.2 Injuries and Damages – FERC Account 925

Utilities record "injuries and damages" in FERC Account 925, which are reported in FERC Form 1.[210] This account records losses and other costs resulting from injury and damage claims, including settlements, offset by credits for reimbursements, dividends, and refunds from insurance companies. Under the 2008 ASCM, all costs included in Account 925 were allowed in the utility's ASC, functionalized using the Labor ratio.[211]

Historically, costs in Account 925 have represented a small portion of a utility's ASC, typically less than 1% of annual Production costs for any single participating utility over the past 20 years.[212] However, in 2023, one utility charged over $700 million of costs to Account 925, largely due to wildfire liability.[213] This single account increased that utility's Production costs by over 12 percent.[214] Furthermore, because costs reported in Account 925 do not necessarily align with costs approved by state regulators, the utility was not required to demonstrate that these costs were actually recovered from regional ratepayers,

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[208] *See* ASCM Workshop 3, Dec. 16, 2025, at 11-21 (describing proposed changes to the ASCM); *see also* Preliminary Draft 2026 ASCM, redline version, Dec. 10, 2025.
[209] 2008 ASCM ROD at 126-27.
[210] *See* 18 C.F.R. § 367.9250.
[211] The Labor ratio functionalizes the costs in an account based on the utility's division of employees. Thus, for instance, if 60 percent of employees' salaries were allocated to Production, 25 percent to Transmission, and 15 percent to Distribution, the LABOR ratio would functionalize costs in the applicable account in this same manner.
[212] *See* Historical Percentages of Account 925 Since 2006, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/202602-20-ascm-925-of-total-production-costs.xlsx.
[213] *See* ASCM Workshop 5, Feb. 13, 2026, at 13.
[214] *Id.*; *see also* Historical Percentages of Account 925 Since 2006, Feb. 20, 2026 (line 64, showing PacifiCorp 925 of $727 million).

as opposed to being assigned by state regulators to company investors or set aside for future rate recovery. Given the potential for other utilities to face significant liability in Account 925, BPA decided to review how "injuries and damages" costs were reported, and to implement additional documentation requirements for Account 925. The additions in the 2026 ASCM related to Account 925 are discussed in more detail in section 5.8.6 of this ROD.

3.4.2.3 Energy Storage Devices

Energy storage devices, such as large-scale batteries, are increasingly integrated into utility system infrastructure. For many years, FERC required utilities to report energy storage plant costs in separate accounts based on their intended use. For example, costs for production-related energy storage were reported in Account 348, "Energy Storage Equipment – Production."[215] However, in Order No. 898, issued on June 29, 2023, FERC revised its System of Accounts, consolidating energy storage costs into a single set of accounts: Accounts 387-387.12, "Energy Storage Plant."[216] Given that energy storage systems often have multiple uses that can evolve over time, BPA has incorporated functionalization options for costs within the Energy Storage Plant account. This reflects the dynamic nature of energy storage device usage in today's utility industry. Additional details on this change can be found in section 5.8.5 of this ROD.

3.4.2.4 Return on Equity

Previous ASCMs both permitted and restricted an IOU's ability to include its state-approved return on equity (ROE) in its ASC.   However, because the 2026 ASCM excludes a utility's transmission assets from ASC, using a state-approved ROE—which is based on a utility owning both generation and transmission assets—is no longer appropriate. Instead, as detailed in section 5.6 of this ROD, the 2026 ASCM introduces a new ROE calculation method for ASC purposes that specifically excludes the ROE associated with transmission assets.

3.4.2.5 Other Adjustments

Other applicable adjustments in the 2026 ASCM are addressed in the sections of this ROD that discuss the relevant sections.

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[215] *See* ASCM Workshop 2, at 22, Dec. 3, 2025.
[216] *See Accounting and Reporting Treatment of Certain Renewable Energy Assets,* 183 FERC ¶ 61,205, at P 7 (June 29, 2023); *see also* ASCM Workshop 2, at 22, Dec. 3, 2025.

3.5 Issues

Issue 3.5.1

Whether transmission costs should be included as part of the average system cost of a utility's resources under Section 5(c) of the Northwest Power Act.

BPA Staff's Proposal

In the 2026 ASCM, BPA Staff proposes to remove most transmission costs from ASC. The definition of "Contract System Cost" has been revised to remove most transmission costs: "Costs of transmission, unless otherwise provided in this ASCM, are not included in Contract System Cost."[217]

BPA explained that transmission costs are not statutorily required to be included as a cost of a utility's resources.[218] Although BPA historically included transmission costs in the ASC, it treated this inclusion as a policy choice rather than a statutory mandate.[219] The most accurate reading of the Northwest Power Act excludes transmission costs from ASC, with a narrow exception. The broader statutory context of how transmission costs are addressed under the Northwest Power Act supports this reading.[220]

The limited exception applies to two narrow sets of costs: those related to purchasing transmission from other utilities (wheeling costs) and those associated with Sales for Resale.[221] Wheeling costs are not, in a functional sense, the "transmission costs" of the subject utility.[222] Rather, they are delivery costs charged by a third-party utility that the subject utility must incur to move its generation to its system. Wheeling costs benefit only the utility that incurred them. Consequently, wheeling costs are fundamentally different from the utility's transmission system costs, which encompass the utility owning, operating, and building a transmission system to serve a broad set of transmission customers. Another notable distinction is that utilities receive a rate of return on their transmission assets and not on their wheeling costs.

Transmission costs associated with sales for resale are presumed to be netted from these sales, meaning BPA is not proposing to add separate transmission costs to the ASC for these transactions.[223] Rather, BPA assumes the utility's sales-for-resale revenue has already been reduced by its transmission expenses (which correspondingly increases the utility's ASC). A utility may perform a direct analysis to demonstrate that its sales-for-resale revenue is not net of its transmission expenses in order to make appropriate adjustments.

Both wheeling costs and transmission for Sales for Resales are costs akin to costs that BPA has, for many years, functionalized to its power rates, and considered a "power cost" in BPA

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[217] 2026 ASCM § 301.2, definition of Contract System Cost.
[218] ASCM Workshop 2, at 12, 17, Dec. 3, 2025.
[219] *Id.* at 13-16.
[220] *Id.*
[221] *Id.* at 17; *see also* 2026 ASCM § 301.4(x)(1)-(2).
[222] 2026 ASCM § 301.4(x)(1).
[223] *Id.* at § 301.4(x)(2).

ratemaking. Under the 2026 ASCM, BPA proposes to allow these two types of costs into a utility's ASC as a cost of that utility's resources.

Parties' Positions

The IOUs contend that BPA's proposal to exclude most transmission costs from ASC diverges from historical practice and violates the Northwest Power Act and its legislative history.[224] They argue that this change lacks the necessary reasoned analysis required for such a significant departure from established agency positions, citing *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co*. The IOUs assert that transmission costs are a legitimate component of a utility's "system costs" for delivering power, which BPA is mandated to calculate under Section 5(c)(7).[225] They further claim that excluding these costs would place an unfair financial burden on IOU customers, contrary to congressional intent.[226] Finally, the IOUs argue that BPA's decision to exclude transmission categories not explicitly excluded in the statute constitutes a direct violation of the NWPA[227] and that the costs included in ASC should not be dictated by the PF Exchange rate.[228]

The WUTC supports the IOUs' position, noting that whether transmission is included or excluded is a "policy call" and that there are sound policy reasons to continue to include these costs.[229]

Public Power customers support BPA's decision to remove transmission costs. Public Power customers argue that BPA lacks the statutory authority to include transmission costs in ASC because the definition of "resource" in Section 3(19) of the Northwest Power Act does not encompass transmission infrastructure.[230] They contend that Congress's specific inclusion of transmission costs in other sections, such as the definition of "cost effective," indicates an intentional exclusion from the "resource" definition, placing such costs outside the legal scope of ASC. Public Power customers emphasize that under *Loper Bright,* the court will independently interpret the Act, and they dismiss the IOUs' argument for including all transmission costs, asserting it lacks support from statutory language or BPA's historical legal interpretation.[231] Furthermore, the Public Power customers reject the IOUs' reliance on floor statements from Senator McClure, stating that plain statutory text should control the interpretation.[232]

AWEC supports BPA's proposal to exclude most transmission costs from ASC.[233]

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[224] IOU Comments (April) at 3-4.
[225] *Id.* at 4.
[226] *Id.* at 4-5.
[227] *Id.* at 11.
[228] *Id.* at 9-10.
[229] WUTC Comments (April) at 1-2.
[230] Public Power Comments (April) at 2.
[231] *Id.* at 3.
[232] *Id.*
[233] AWEC Comments (April) at 7.

Evaluation of Positions

1. Statutory Text: Sections 5(c)(1), (7), and Definitions of Resource, Electric Power

Contrary to the IOUs' assertion, Congress did not intend that transmission costs be included in the "average system cost" of a utility's resources under Section 5(c)(7) of the Northwest Power Act.[234] It is axiomatic that statutory interpretation begins with the plain language of the statute.[235] In forming its interpretation, BPA is also guided by the Supreme Court's decision in *Loper Bright*, wherein the Court observed that "[i]n the business of statutory interpretation, if it is not the best, it is not permissible."[236] BPA also recognizes its unique responsibilities in implementing the REP, which the Supreme Court states requires BPA to "manage the complex relationship among the[] various aspects of the [Northwest Power Act] . . . ."[237]

Under Section 5(c)(7) of the Northwest Power Act, a utility's "'average system cost' for electric power" is to be determined "on the basis of a methodology developed for this purpose. . ."[238] The term "average system cost" is used three different times in the immediate context of Section 5(c): "average system cost of that utility's resources,"[239] "average system cost of power,"[240] and "'average system cost' for electric power."[241] These descriptors—"of that utilities resources," "of power," "for electric power"—limit and inform what Congress intended by the phrase "average system cost." The common thread is their focus on the utility's assets that produce or support electric power production, none of which contemplate transmission costs. As such, BPA finds that the best reading of the statute is to exclude transmission costs from a utility's ASC.[242]

Statutory definitions affirm this interpretation. Sections 5(c)(4) and 5(c)(7) explicitly refer to "electric power" and "power." These terms support BPA's interpretation. The term "electric power" is a defined term under the Act, meaning "electric peaking capacity, or electric energy, or both."[243] The term "power" is not further defined in the Northwest Power Act, but its use is generally synonymous with the term "electric power."[244]

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[234] 16 U.S.C. § 839c(c)(7).
[235] *Lopez v. Garland*, 116 F.4th 1032, 1043 (9th Cir. 2024).
[236] *Loper Bright Enters. v. Raimondo*, 603 U.S. 369, 400 (2024).
[237] *Alcoa*, 467 U.S. at 400.
[238] 16 U.S.C. § 839c(c)(7).
[239] 16 U.S.C. § 839c(c)(1).
[240] 16 U.S.C. § 839c(c)(4).
[241] 16 U.S.C. § 839c(c)(7).
[242] *Cent. Mont. Elec. Power Co-op., Inc. v. Administrator of Bonneville Power Admin.,* 840 F.2d 1472, 1477 (9th Cir. 1988) ("Absent a clearly expressed legislative intent to the contrary, the plain language must ordinarily be regarded as conclusive.").
[243] 16 U.S.C. § 839a(9).
[244] *E.g.,* "reliable power supply" (§ 839(2) (purpose)); "power system" (in reference to the power plan purpose of NWPA) (§ 839(3)(B)); "power generating facilities" (§ 839(6)) (in reference to protect /mitigate/enhance F&W purpose); "In determining the amount of power that a conservation measure or other resource may be expected to save . . ." (§ 839(a)(4)(C)) (definition of "cost effective"); "'Customer' means anyone who contracts for the purchase of power from the Administrator pursuant to this chapter"

Importantly, "transmission costs" are not included in the definition of "electric power" or implied by the context of "power" in other areas of the Act. Congress' use of these terms is evidence of its intent to exclude transmission costs from the ASCM.

While Sections 5(c)(4) and 5(c)(7) explicitly refer to "power," Section 5(c)(1) refers to "resources." However, the term "resources" is defined by the Act 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."[245] In all instances of its usage in the Northwest Power Act, the term "resource" refers to generating facilities, power contracts, or conservation.[246] Conversely, in *no* instance is the term "resource" used to refer to transmission facilities or costs. Given this definition and context, "resource" is not an ambiguous term. "Resource" unambiguously does not refer to transmission facilities, and Congress' use in Section 5(c)(1) affirms BPA's interpretation.

The IOUs claim that excluding transmission costs from ASC is "inconsistent with the NWPA Section 5(c)(7)."[247] The IOUs claim BPA must calculate the "system costs" of a utility's resources to bring power to its load. The IOUs claim that a "notable portion of" the costs of serving utility loads with resources "indisputably includes transmission costs."[248] The IOUs contend that Congress, by using the term "system cost" in relation to a utility's resource, intended for BPA to calculate the total cost a utility incurs to deliver power to its customers.[249]

The IOUs' argument is not persuasive. The IOUs' suggestion that the term "system cost" can be interpreted to include transmission costs ignores the immediate context in which the term is used. Specifically, Congress describes and limits the relevant "system costs" to those associated with "that utility's resources," "of power," and "for electric power." None

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(§ 839a(7)); "'Direct service industrial customer' means an industrial customer that contracts for the purchase of power from the Administrator for direct consumption" (§ 839a(8)); "which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period" (§ 839a(13)(B)) (definition of NLSL); "firm power customers of the Administrator . . ." (§ 839a(17)) (definition of reserves); "firm power forecast to be sold by the Administrator during the year to be funded" (§ 839b(c)(10(A), (B)) (Council funding); "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]. Such sales shall be at rates established pursuant to section 839e of this title." (§ 839c(a)).

245 16 U.S.C. § 839a(19).

246 "Federal base system resource" (§ 839a(10)); "major resources" (§ 839a(12)); "renewable resource" (§ 839a(16)); "other resources" (§ 839b(e)(1)); "operate resources" (§ 839(5)(B)); "power resources" (§ 839b(e)(3)(D)); "generating resources" (§ 839b(e)(1)); "firm peaking and energy resources" (§ 839c(b)(1)(A)); "resources other than conservation" (§ 839d(h)(4)); "experimental resources" (§ 839e(b)(2)); "amount of energy included in the resources of such customer" (§ 839f(c)).

247 IOU Comments (April) at 4.

248 *Id.*

249 IOU Comments (April) at 4.

of these modifying terms evidence a legislative intent to include a utility's transmission system costs.

The IOUs' position that Congress intended "system cost" in Section 5(c)(7) to refer to the totality of an entity's cost (resource and transmission costs) is also belied by Congress' use of "system cost" elsewhere in the Act. When Congress intends "system cost" to refer to something other than "electric power" and "resources," it says so. For instance, in Section 7(a)(2)(B), Congress directs the FERC to evaluate whether BPA's rates are based on "the Administrator's *total* system costs."[250] In that context—with the use of the adjective "total" and no further limiting clause—it is clear that the term "system cost" is to include all the costs the Administrator incurs. In Section 5(c), however, the term "system cost" specifically refers to a particular *type* of cost: that of a utility's "resources" or "for electric power . . . ."[251] Therefore, "system cost" under Section 5(c) of the NWPA is not a standalone term granting BPA discretion to include any "system costs" the utility incurs; its scope is limited by the accompanying text, which excludes transmission.

Elsewhere in the Act, in defining "cost effective" in Section 3(4)(a), Congress used the term "system cost" and explicitly defined it to include "the cost of distribution and transmission to the consumer . . . ."[252] By defining "system cost" to include transmission costs in the context of the term "cost effective," Congress demonstrated its ability to direct the accounting of transmission costs under specific circumstances. If the term "system cost" already encompassed transmission cost, Congress would not have needed to specify its inclusion here. Notably, Congress did not extend Section 3's definition of "system cost" to any other part of the statute, but explicitly limited its use to only the term "cost effective."[253] The fact that Congress expressly included transmission costs within the term "system cost" in one part of the statute, but instead referred to "average system cost of . . . resources" in another, serves as strong contextual evidence that Congress did not intend for BPA to include transmission costs in the ASCM.[254]

The IOUs' other main statutory argument for including transmission costs in a utility's ASC relies on Section 5(c)(7)'s explicit exclusions. The IOUs note that Section 5(c)(7) excludes "only" three categories of costs from the utility's ASC.[255] Thus, the IOUs contend that by excluding transmission, BPA is improperly "creating additional categories of excluded costs not permitted in the statute."[256] The IOUs argue that BPA's decision to exclude most transmission costs is a "direct violation of the NWPA."[257]

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[250] 16 U.S.C. § 839e(a)(2)(B) (emphasis added).
[251] 16 U.S.C. § 839c(c)(1), (7).
[252] 16 U.S.C. § 839a(4)(A)-(B).
[253] *Id*. ("For purposes of this paragraph . . . .").
[254] *See Idaho Conservation League v. Bonneville Power Admin.*, 83 F.4th 1182, 1184-85 (9th Cir. 2023) ("When Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (internal citation omitted).
[255] IOU Comments (April) at 11.
[256] *Id.*
[257] *Id.*

Section 5(c)(7)'s exclusions, in fact, further support BPA's interpretation that transmission costs be excluded from ASC. The costs listed for exclusion from the ASCM in Sections 5(c)(7)(A)-(C) are all physical electric power resource production-related costs: "(A) the cost of additional *resources* in an amount sufficient to serve any new large single load of the utility;" "(B) the cost of *additional resources* in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980;" and "(C) any costs of any *generating facility* which is terminated prior to initial commercial operation."[258] The first two exclusions ((A) and (B)) refer to "resource" costs associated with serving or meeting load. Power-producing resources meet load—not transmission. The third exclusion directly refers to costs of a "generating facility," which unambiguously excludes "transmission" facility costs. Given that Congress explicitly listed specific types of power generation-related costs for exclusion from the ASC, it logically follows that the ASC must have been made up of only power-generating assets to begin with.[259]

Furthermore, Section 5(c)(7)'s exclusions demonstrate why retaining transmission costs in the 2026 ASCM would be a flawed statutory approach. For example, a generating plant terminated before commercial operation must be excluded from ASC.[260] However, if a utility had constructed extensive transmission upgrades to support that plant, those transmission costs could—under the IOUs' interpretation—arguably still be included in the utility's ASC as a cost (because "transmission" costs are not "generating facility" costs), while the costs of the actual terminated plant would be excluded. There is no basis to assume Congress intended this counterintuitive result. Instead, since Congress focused solely on excluding "any cost of any generating facility," and did not refer to any other costs—such as transmission or distribution costs—it logically follows that Congress must have assumed such transmission or distribution costs were already omitted and did not need express exclusion.

In addition, the Court has already rejected the IOUs' claim that Section 5(c)(7) is an exclusive list. In *PacifiCorp*, the Court found that BPA need not include "all costs" incurred by an IOU in its ASC.[261] The Court noted that the "statutory scheme militates against petitioners' theory that Congress intended all costs to be included except those specifically excluded in Section 5(c)(7)."[262] The Court cited with approval the Senate Report for Senate Bill 885 (the precursor to the NWPA), which said that 5(c)(7) "contains a list of costs to be excluded in the determination of average system costs; additional exclusions may be incorporated in the methodology for determining average system costs under this section."[263] Thus, the Court found that "neither the language of the statute nor the

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[258] 16 U.S.C. § 839c(c)(7)(A)-(C) (emphasis added).
[259] This legal principle is akin to *noscitur a sociis,* wherein meaning from a term can be found from the terms used around it. *Yates v. United States,* 574 U.S. 528, 543 (2015) ("[W]e rely on the principle of *noscitur a sociis*—a word is known by the company it keeps—to 'avoid ascribing to one word a meaning so broad that it is inconsistent with its accompanying words, thus giving unintended breadth to the Acts of Congress.'").
[260] 16 U.S.C. § 839c(c)(7)(C) ("any costs of any generating facility which is terminated prior to initial commercial operation.")
[261] *PacifiCorp*, 795 F.2d at 822.
[262] *Id.*
[263] *Id.* (*quoting* S. Rep. No. 272, 96th Cong., 1st Sess. 27 (1979)).

legislative history supports a holding that discretion to exclude costs is narrowly confined."[264] The Court's finding in *PacifiCorp*, which applied to BPA's exclusion of federal income tax and return on equity, supports BPA's decision here to exclude transmission costs from ASC, particularly where that exclusion is consistent with the plain language of the Act.

2. Broader Statutory Context: Sections 7(a)(2)(C), 7(b)(1), 7(b)(2).

The broader context of the terms "resource" and "transmission costs" as used in the Northwest Power Act also supports BPA's interpretation to exclude transmission costs from the ASCM. Statutory language must not be read in a vacuum but within the "overall structure and design" of the statute.[265] Here, Congress distinguished between "transmission costs" and "resource" costs in several places in the Northwest Power Act, confirming that Congress meant the two types of costs to be distinct, and in places where Congress wanted to discuss both, it did. This context supports BPA's interpretation to exclude transmission costs from the ASCM.

a. Section 7(a)(2)(C)

First, in Section 7(a)(2)(C), Congress requires FERC to ensure that BPA's transmission rates "equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system."[266] The reference to "costs of the Federal transmission system" shows Congress knew how to direct that "transmission costs" be an attribute of a particular rate. In Section 5(c), Congress said nothing about transmission costs in the definition of the term "average system cost of resources," which supports BPA's interpretation that Congress did not intend to include transmission costs in the ASCM.

b. Sections 7(b)(1) and 7(b)(2)

Second, the rate provisions in Sections 7(b)(1) and (2) of the Northwest Power Act approach the utility's ASCs from the perspective of *energy* and *power* costs. Outside of Section 5(c), the other major provision of the Northwest Power Act to use the term "average system cost of that utility's resources" is Section 7(b). There, Congress directs BPA to meld the costs of the "electric power" acquired under Section 5(c) with the costs of the "electric power" produced by Federal base system resources. Section 7(b)(1) is built from the perspective of costs related to resources that produce (or can produce) electric power.[267]

The term "Federal base system resources" only refers to the hydroelectric projects and related thermal plants.[268] Congress' decision to use resource-related terms indicates

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[264] *Id.*
[265] *Idaho Conservation League v. Bonneville Power Admin.*, 142 F.4th 636, 642 (9th Cir. 2025) (*ICL II*).
[266] 16 U.S.C. § 839e(a)(2)(C).
[267] *See* 16 U.S.C. § 839e(b)(1). ("The Administrator shall establish a rate or rates of general application for **electric power** sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 839c(c) of this title . . .")
[268] 16 U.S.C. § 839a(10) ("'Federal base system resources' means—(A) the Federal Columbia River Power System hydroelectric projects; (B) resources acquired by the Administrator under long-term contracts in

Congressional intent to limit the costs melded by the Section 7(b) rate provision to resource-related costs.[269] The 7(b)(1) rate is essential to the REP. The Section 7(b)(1) rate establishes the rate (the PF Exchange rate) to be charged to utilities in the REP under Section 5(c), in order to calculate the "cost benefit[]" under Section 5(c)(3). Given that direct connection, Congress logically intended for the two rates to be made up of the same *type* of costs. Section 7(b)(1) discusses a rate comprised of resource and energy costs, and consequently, so must the ASC BPA develops under Section 5(c)(7).

The IOUs object to BPA's attempt to match the ASC with the costs included in the PF Exchange rate, calling this approach "backwards."[270] The IOUs argue that whether transmission is an appropriate system cost is determined by Section 5(c)(7); if it is, then an adjustment must be made to the PF Exchange rate for consistency.[271] When determining how to develop the ASCM, the IOUs argue "the makeup of the PF Exchange rate cannot be considered . . . ."[272] The IOUs contend there is no requirement that symmetry exists with the PF Exchange rate,[273] and that a utility's ASC is based on that utility's resources, not whether or how those costs relate to the PF Exchange rate or Section 7(b)(2).[274] The IOUs contend that BPA's "consideration" of the PF Exchange rate in determining a utility's ASC "violates the NWPA."[275]

BPA disagrees that its interpretation is flawed simply because it considers how the ASC is used elsewhere in the statute. Ultimately BPA is responsible for "manag[ing] the complex relationship among the[] various aspects of the [Northwest Power Act] . . . ."[276] This responsibility includes determining ASCs so that they align with *both* Sections 5(c) and 7(b). Section 5(c) and Section 7(b) were designed to work together, with the authority to provide REP benefits under Section 5(c) expressly limited by Section 7(b)—specifically, Section 7(b)(2). The Court made this relationship clear in *PGE*, noting that "whenever BPA engages in a purchase and exchange of power—whether on a yearly basis, under a REP program, or pursuant to a settlement agreement—BPA acts pursuant to its § 5(c) authority, and is thus subject to the Congressionally imposed limitations on that authority as expressed in § 5(c) and § 7(b)."[277] Consequently, analyzing the PF Exchange rate structure (which excludes transmission costs) to inform the ASC structure is not a backward approach. Rather, it is a sound interpretation of statutory construction that respects the

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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.").
[269] BPA must, of course, recover its "total system costs" in its rates, *see* 16 U.S.C. § 839e(a)(2)(B), and before functionally unbundling its power and transmission costs to separate rate classes in 1996, BPA allocated a portion of its transmission costs to its power rates. This allocation to power rates occurred as a matter of cost recovery (*see* 16 U.S.C. § 839e(a)(1)), and rate design, and not as a requirement of Section 7(b)(1).
[270] IOU Comments (April) at 9.
[271] *Id.*
[272] *Id.*
[273] *Id.*
[274] *Id.*
[275] *Id.*
[276] *Alcoa*, 467 U.S. at 400.
[277] *PGE,* 501 F.3d at 1032.

principle that statutory provisions must be read "in their context," within the "overall statutory scheme," to ensure each part "fit[s] harmoniously as part of a symmetrical and coherent statutory scheme."[278]

The connection between a utility's ASC and the PF Exchange rate is all the more critical to maintain because of the statutory limitations of the Section 7(b)(2) rate test. Under this test, Congress directs BPA to compare the projected power rates it plans to charge Public Power customers against a hypothetical rate.[279] This hypothetical rate is derived from "power costs"[280] adjusted by five statutory assumptions, one of which requires BPA to remove the costs of the Section 5(c)(1) exchange.[281] Crucially, this assumption treats the Section 5(c)(1) exchange as being comprised of only "power costs." Because "power costs" and "transmission costs" are legally distinct, transmission costs fall outside of Section 7(b)(2)'s express framework and protections. Consequently, including transmission costs in the ASC leads to an absurd result: because an IOUs' transmission costs are not a "power cost," they would be excluded from the Section 7(b)(2) rate test operations, and an IOU could receive REP benefits funded by these transmission costs completely insulated from rate-test protections. This outcome renders the Section 7(b)(2) rate test protections meaningless and directly contradicts the Court's clear guidance in *PGE*: "§ 7(b)'s rate ceiling analysis provides a means of determining whether REP benefits will impact the preference customers' power rates and, if so, § 7(b)(3) ensures that the preference customers' power rates are unaffected by the implementation of the REP."[282] Ultimately, allowing transmission costs in ASC results in costs bypassing the Section 7(b)(2) rate test, leaving Public Power customers vulnerable to the very rate impacts Congress sought to prevent. Excluding transmission cost from ASC avoids this absurdity, and ensures the full and proper operation of the Section 7(b)(2) rate test.

The IOUs argue that BPA's current view—that the operation of PF Exchange rate matters to the development of the ASCM—is contrary to a similar argument BPA addressed in the 2008 ASCM ROD.[283] In that context, the IOUs claim BPA determined that the ASCM was not the appropriate forum to create symmetry between the PF Exchange rate and ASCM because the only question answered by the ASCM is "the system costs incurred by utilities."[284] The IOUs note that BPA does not decide how to structure the PF Exchange rate in the ASCM, which must be decided in each rate case.[285] Whether or how the PF Exchange rate can be made symmetrical to the ASC is a ratemaking question that does not alter the

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[278] *Rodriguez v. Holder Jr.*, 619 F.3d 1077, 1079 (9th Cir. 2010)
[279] 16 U.S.C. § 839e(b)(2).
[280] *See* 16 U.S.C. § 839e(b)(2), ("the projected amounts to be charged for firm power for the combined general requirements of [Public Power customers] . . . may not exceed in total . . .an amount equal to the *power costs* for general requirements of such customers if, the Administrator assumes that" (emphasis added).
[281] *Id.* at § 839e(b)(2)(C) (noting BPA is to assume in the hypothetical rate that "no purchases or sales by the Administrator as provided in section 839c(c) of this section were made during such five-year period.")
[282] *PGE*, 501 F.3d at 1021.
[283] IOU Comments (April) at 10.
[284] *Id.* (citing *See* 2008 ASCM Record of Decision at 142).
[285] *Id.*

statutory requirements of Section 5(c)(7).[286] The IOUs argue that by excluding transmission costs from the Draft ASCM to create symmetry with the PF Exchange rate, BPA is "doing exactly what it refused to do in the 2008 ASCM ROD."[287]

BPA disagrees that it "refused"[288] to consider symmetry in the 2008 ASCM and punted that issue to the rate case. In fact, symmetry between the ASC and PF Exchange rate was essential—both then and now—to ensure an "apples-to-apples" comparison of the PF Exchange rate to the utility's ASC.[289] As BPA explained:

> BPA agrees there needs to be consistency between the transmission costs included in the PF Exchange rate and the transmission costs included in ASC. The purpose of comparing a Utility's ASC with the PF Exchange rate is to calculate the REP benefits for an exchanging Utility's residential consumers. This comparison can only work if the two rates being compared are constructed of the same component parts. Without this symmetry, the result would be an "apples to oranges" comparison that would inappropriately increase or decrease REP benefits to the exchanging utilities.[290]

In the 2008 ASCM ROD, BPA decided to address the symmetry question by proposing to include "symmetrical" transmission costs in the PF Exchange rate.[291] That decision was fueled by policy considerations, not statutory interpretations.[292]

Here, however, BPA finds that, as a matter of law, a utility's ASC must be based on a utility's cost of resources, not its transmission costs. The approach adopted in the 2026 ASCM—excluding transmission costs from ASC (which does not include power costs of third-party wheeling costs and netted sales for resale)—maintains the symmetry originally sought in the 2008 ASCM ROD while also complying with the clear statutory language. Thus, in addition to the plain language text and context discussion above (which clearly shows transmission costs are not a cost of resources), BPA's interpretation is supported by construing the Act as a whole. BPA's interpretation ensures that the symmetry Congress intended to exist between Section 5(c)—which calculates the ASC—and the Section 7(b)—which calculates the PF Exchange rate—is maintained and affirmed.

3. <u>*Legislative History and Purpose of REP*</u>

The statutory text in context is determinative in excluding transmission costs from ASC. The legislative history and general context and purpose of the REP further support BPA's

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[286] *Id.*
[287] *Id.* (citing 2008 ASCM Record of Decision at 142).
[288] *Id.*
[289] 2008 ASCM ROD at 136.
[290] *Id.* at 130.
[291] *Id.* at 131 ("Although BPA cannot commit to developing the PF Exchange rate in any way, it can commit to initially propose in its rate proceedings to include transmission costs in the PF Exchange rate so that it will be 'symmetrical' to the ASCs developed under the ASCM.").
[292] *See id.* at 128-34.

interpretation. A foundational principle of statutory interpretation directs that the text be read in context and in view of the overall statutory scheme and design Congress had in mind.[293]

The IOUs contend that legislative history supports an interpretation that BPA is required to "capture all of a utility's costs with limited exceptions."[294] They cite to a November 19, 1980, statement from Sen. McClure, which they argue notes BPA was expected to pay for the "full cost of power that a utility exchanges with BPA, subject to the limited exclusions in Section 5(c)(7), so that IOU customers 'will not be forced to shoulder an extra financial burden.'"[295] The IOUs contend that by excluding most transmission costs, BPA is setting up a "disparate system whereby IOU customers can recoup only a portion of the total system costs to which they are subject . . . ," an outcome the IOUs contend leads to an "extra financial burden that Congress expressly prohibited and sought to avoid under the NWPA."[296]

Public Power customers disagree with the IOUs that the floor statements of Sen. McClure influence the outcome of this issue.[297] They note Sen. McClure's statements are not authoritative legal precedent, and that plain statutory text controls.[298]

BPA finds that its interpretation is further supported, not undermined, by the legislative history underlying Section 5(c), as well as Congress's overarching statutory purpose for the REP. First, the statement the IOUs cite from Sen. McClure says nothing about transmission costs. It simply notes that the utility is expected to exchange the "full cost of *power* exchanged to the BPA,"[299] which BPA proposes to do. Sen. McClure's specific concern with "forc[ing]" the IOUs to "shoulder an extra financial burden" is without any context or substance, so there is no basis to read into that statement that it was intended to refer to transmission costs, as suggested by the IOUs.

The House and Senate Reports, in contrast, square entirely with BPA's interpretation. As noted by the Court in *PacifiCorp*, the Senate Report to the Northwest Power Act notes that Section 5(c)(7) "contains a list of costs to be excluded in the determination of average system costs; additional exclusions may be incorporated in the methodology for determining average system costs under this section."[300] From this the Court concluded

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293 *Idaho Conservation League v. Bonneville Power Admin.*, 83 F.4th 1182, 1192 (9th Cir. 2023) ("When interpreting a statutory provision, we consider not only its ordinary meaning, but also its place within the broader statutory scheme of which it is a part.") (citation omitted); *ICL II*, 142 F.4th at 642 ("In resolving that dispute, we do not read the words of section 4(h)(11)(A) in a vacuum. To the contrary, '[i]t is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.'" (alternation in original) (quoting *Davis v. Mich. Dep't of Treasury*, 489 U.S. 803, 809 (1989))).
294 IOU Comments (April) at 4.
295 *Id.* at 4-5 (*citing* Cong. Rec. S 14698 (daily ed. Nov. 19, 1980) (statement of Sen. James McClure)).
296 *Id.* at 5.
297 Public Power Comments (April) at 3.
298 *Id.*
299 Cong. Rec. S 14698 (daily ed. Nov. 19, 1980) (statement of Sen. James McClure) (emphasis added).
300 *PacifiCorp*, 795 F.2d at 822 (*citing* S. Rep. No. 272, 96th Cong., 1st Sess. 27 (1979)).

that "neither the language of the statute nor the legislative history supports a holding that discretion to exclude costs is narrowly confined."[301]

In terms of the scope of the REP, the legislative history is also clear that Congress intended to address wholesale rate disparity associated with *resource* costs, not some broader category of total system costs of both BPA and the utility. Thus, for instance, in the House Report (Part II), Congress explained:

> This exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers or preference utilities in the region.[302]

Indeed, BPA could find no mention in the legislative history of Congress attempting to equalize the *transmission* costs between BPA and the IOUs.

3. *Historical Legal Interpretation*

The IOUs argue that "[f]or the first time in the history of the ASCM" BPA proposes to exclude all transmission costs from the ASCM other than those included in Account 565 (Transmission of Electricity by Others) and Account 447 (Sales for Resale).[303] The IOUs claim BPA's proposal is inconsistent with BPA's historical position.[304] The IOUs contend that BPA has offered no "explanation or analysis" that would allow it to change or alter its "determinative conclusion in 2008 that transmission costs are a system cost to IOUs of delivering power to customers and thus should properly be included as a cost in calculating ASCs."[305] The IOUs also argue the 2008 ASCM ROD has been in effect for nearly 20 years, and BPA's "unexplained departure from its interpretation of the NWPA to now exclude most transmission costs from the ASCM is arbitrary and capricious."[306] The IOUs cite to the 1981 ASCM, 1984 ASCM, and 2008 ASCM, for the contention that BPA fails to address "decades of compelling policy reasons" it has relied on for including transmission costs in a utility's ASC, particularly as reasoned in the 2008 ASCM.[307]

Contrary to the IOUs' claims, BPA has not changed its legal position that transmission costs are not resource costs that must be included in a utility's ASC. BPA has consistently maintained that transmission costs do not constitute resource costs under the terms of the Northwest Power Act. Rather, where BPA's position has evolved is concerning the degree of statutory discretion available to rely on policy considerations to include costs otherwise excluded from ASC. To that point, BPA has long acknowledged the tension between its prior policy on transmission costs and the statutory text, consistently noting that including such costs was never statutorily required. The record fully supports this position.

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[301] *Id.*
[302] H.R. Rep. No. 976 (Part II), 96th Cong., 2d Sess. 35 (1980).
[303] IOU Comments (April) at 3.
[304] *Id.*
[305] *Id.* at 5.
[306] *Id.*
[307] *Id.*

a. 1981 ASCM

Beginning in 1981, BPA considered the inclusion of transmission costs in a utility's ASC as a discretionary feature of the ASCM. In the 1981 ASCM ROD, there is no detailed discussion on the reason for including transmission costs in ASC. This is not surprising because the 1981 ASCM was developed based on a negotiated settlement, "which had resolved nearly all issues raised by parties in the consultation proceeding."[308]

Nonetheless, by allowing all transmission costs into a utility's ASC, BPA acknowledged that it included costs not explicitly contemplated by the Act. Because Section 5(c) allows *any* utility to exchange with BPA, including Public Power customers, a number of public customers argued that they should be allowed to enter the exchange and exchange their *transmission costs alone* with BPA.[309] That is, a Public Power customer with no physical resources, and who purchased only BPA power, would exchange with BPA the costs of their transmission system, and receive resulting REP benefits.[310] BPA tried to discourage Public Power customers from participating in the REP in this manner by initially imposing additional requirements for publics engaging in a "transmission only" REP exchange. Following Public Power customer opposition, BPA dropped those requirements.[311] In permitting Public Power "transmission only" cost exchanges, the BPA Administrator recognized that "partial regional sharing of the costs of [transmission and sub-transmission] facilities" was "not specifically intended by the Regional Act" but nonetheless was "consistent with postage stamp rates."[312] Importantly for this discussion, while BPA ultimately allowed utilities to include their transmission costs in ASC in the 1981 ASCM, it did so from the perspective that this allowance was "not specifically intended by the Regional Act . . . ."[313]

b. 1984 ASCM

Three years later, in the 1984 ASCM ROD, (which was *not* the product of a negotiated outcome), BPA stated again its legal position that transmission costs were not a required cost of a utility's average system costs of resources. There, BPA directly stated its position that transmission costs were *not* required to be included in a utility's ASC as a matter of law. BPA stated:

> From a legal standpoint, BPA believes that there is no requirement that transmission costs be included in resource costs for calculation of the residential exchange subsidy. BPA is directed by section 5(c)(7) to develop a methodology for calculating "the average system cost of that [participating]

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[308] Administrator's Record of Decision, Average System Cost Methodology, June 4, 1984, at 10 ("1984 ASCM ROD"), *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/1984-ascm-rod.pdf; *see also id.* at 36.
[309] 1981 ASCM ROD at 20.
[310] *Id.*
[311] *Id.*
[312] *Id.*
[313] *Id.*

> utility's resources . . . ." Resource is synonymous with generating facilities and conservation measures, not with transmission facilities.[314]

BPA further found that allowing transmission costs in ASC was "permitted by the Act but not required"[315] and whether these costs were included or excluded was a matter of "policy."[316] Ultimately, because of "definitional problems" in finding an appropriate cut-off of transmission costs, BPA decided to retain existing transmission costs in ASC, and limit the inclusion of new transmission costs to a specific test.[317] Even so, BPA found the case for including transmission costs in any amount in ASC as not "compelling."[318]

c. 2008 ASCM

In the 2008 ASCM ROD, BPA reiterated its view that including transmission cost in ASC was not required as a matter of law. In deciding to allow all transmission costs into ASC, BPA reaffirmed that it was neither "required [n]or prohibited from including transmission costs in ASC."[319] Instead, whether transmission costs were allowed in ASC was "a matter of policy."[320] BPA then explained a number of policy reasons for allowing transmission costs back into ASC.[321]

d. Summary

Taken together, the record indicates that BPA has not altered its legal interpretation regarding whether transmission costs constitute a resource cost. From the outset of the ASCM, BPA has maintained that transmission costs are not a required part of a utility's average system cost of resources. Their inclusion in ASC was always considered a policy choice, driven by policy factors.

To the extent BPA's legal interpretation can be viewed as having changed, it has done so only in the sense that it has evolved concerning the extent of BPA's discretion to include or exclude costs that do not explicitly align with the statute's plain language. BPA's decision to re-evaluate this discretionary authority in shaping the ASCM is well-founded. The administrative law framework, which previously may have allowed BPA to choose to include or exclude transmission costs in ASC in 1984 and 2008 based on policy factors, has changed. In considering whether the Act "permits" the inclusion of a cost not expressly allowed as a matter of policy, BPA must address the Supreme Court's ruling in *Loper Bright*: "It therefore makes no sense to speak of a 'permissible' interpretation that is not the one the court, after applying all relevant interpretive tools, concludes is best. In the business of statutory interpretation, if it is not the best, it is not permissible."[322] While establishing the ASCM is a highly technical decision involving "factual premises within [an agency's]

[314] 1984 ASCM ROD at 40 (internal citation omitted).
[315] *Id.* at 41.
[316] *Id.*
[317] *Id.* at 39-40.
[318] *Id.* at 42.
[319] 2008 ASCM ROD at 127.
[320] *Id.*
[321] *Id.* at 128-41.
[322] *Loper Bright*, 603 U.S. at 400.

expertise,"[323] BPA recognizes that "Courts interpret statutes, no matter the context . . . ."[324] Consequently, BPA adopts here what it believes is the "best" interpretation of the statutory language, which is to exclude transmission costs – a cost the Northwest Power Act treats distinctly from resources costs.

4. *<u>Policy Concerns Cannot Overcome Statutory Language or the REP's Stated Purpose.</u>*

Apart from statutory arguments, the IOUs and WUTC object to BPA's proposal to remove transmission costs on the grounds that they believe BPA has abruptly changed its policy stance without adequate explanation.[325] Their comments highlight BPA's previous policy and factual arguments that supported including transmission costs in the ASC.[326] The IOUs argue that BPA has relied on "decades of compelling policy reasons" for including transmission costs in a utility's ASC, citing positions taken in the 2008 ASCM.[327] They contend that BPA has failed to address these prior policy decisions in its current choice to exclude transmission costs.[328]

BPA need not revisit its policy rationale for including transmission costs in ASC now that it has determined, as a matter of law, that transmission costs should not be included in a utility's average system cost of resources. BPA adopts here what it considers the most accurate interpretation of the law, which excludes these costs.

Moreover, including a non-statutory cost like transmission in the ASC for "policy" reasons undermines the core statutory objective Congress envisioned for the REP. For one, as discussed above, adding transmission costs to a utility's ASC undermines the rate protections Congress afforded Public Power under the Section 7(b)(2) rate test.

Additionally, the clear statutory purpose of the REP is to provide a measure of "parity" between the wholesale resource costs of BPA (which are paid for by Public Power customers) and those of the IOUs.[329] As noted in the House Report (Commerce) in reference to the Section 5(c) exchange:

> The requirement is not likely to result in parity in the retail rates being paid by consumers of preference customers and consumers of investor-owned utilities, but it should equalize the wholesale costs of the electric power with a resulting benefit [to] the investor-owned utilities' customers.[330]

Logically, the driver of that rate parity should be the party's respective resource costs. Including transmission costs in ASC as a policy matter would distort this designed parity, allowing a non-statutory cost to drive the calculation. In simple terms, a policy choice to

323 *Id.* at 402.
324 *Id.* at 403.
325 IOU Comments (April) at 3, 5, 6-10; WUTC Comments (April) at 2.
326 IOU Comments (April) at 3, 5, 6-10; WUTC Comments (April) at 2-3.
327 IOU Comments (April) at 5.
328 IOU Comments (April) at 8, 10; WUTC Comments (April) at 2-3.
329 *See Alcoa* at 399; *PacifiCorp*, 795 F.2d at 818; *Cal. En. Resource Comm'n v. Johnson*, 807 F.2d 1456, 1459-60 (9th Cir. 1987).
330 H.R. Rep. No. 976 (Part I), 96th Cong., 2d Sess. 60 (1980).

include transmission costs has the counterintuitive effect of potentially increasing a utility's REP payments, not because its resource costs are higher than BPA's, but because its *transmission costs* are. BPA cannot agree that Congress intended for a utility to receive higher REP payments through an inflated ASC driven by transmission costs.

This concern is far from theoretical; transmission costs are consuming an increasingly large share of utilities' ASCs. When BPA initially decided to include transmission costs in the ASC, they represented approximately 12% of utilities' total costs.[331] By the 2026 ASC review process, that share had grown to 15.5%.[332] For a non-statutory cost, this growth is alarmingly rapid. The pace of this increase is also particularly striking. While utility production (generation-related) costs have increased by an average of 8% annually, aggregate utility transmission costs have risen by 12% annually—a rate nearly 50% higher.[333] This trend highlights the flaw in BPA's previous approach of including non-statutory transmission cost in a utility's ASC based solely on a policy rationale. Nothing in the Northwest Power Act or its extensive legislative history suggests that BPA should provide "cost benefits" for rising transmission costs. Yet, that is exactly what BPA's previous flawed approach did, and what the IOUs are requesting BPA continue to do.

5. *Conclusion*

In conclusion, the statutory text, context, statutory scheme, legislative history, and case law all militate in favor of excluding transmission costs from a utility's average system cost of resources. While the IOUs claim "system cost" includes all transmission costs, this position lacks statutory support. BPA also disagrees with the IOUs' view of Section 5(c)(7) as an exclusive exclusion list, a point on which the Court in *PacifiCorp* has already decided. BPA's legal interpretation is not new but has been at the core of its approach to the ASCM since it was first created in 1981.

Draft Decision

Under Section 5(c) of the Northwest Power Act, the average system cost of a utility's resources does not include a utility's transmission costs.

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[331] *See* ASC Transmission Percentage (Historical), Sep. 11, 2026, (on file with author). For some utilities, transmission costs are now as much as 20 percent of their ASC. *See id.* (showing transmission costs accounting for 20% of Avista's ASC costs in the Base Year of 2023, and 21% in Base Year of 2021).
[332] ASC Transmission Percentage (Historical), Sep. 11, 2026, (on file with author).
[333] *Id.*

Issue 3.5.2

Whether the 2026 ASCM should be modified to require utilities to remove costs disallowed by state regulatory bodies from the Appendix 1.

BPA Staff's Proposal

The primary source of utility data for determining a utility's ASC is the utility's FERC Form 1.[334] Except for select areas, the FERC Form 1 is the cost, resource, and load data used in determining a utility's ASC.

Parties' Positions

The Public Power customers argue that the FERC Form 1 permits IOUs to include costs disallowed by state regulators, contending that FERC Form 1 is a financial record, not a ratemaking document.[335] They propose that any disallowed costs identified by an IOU's regulatory commission should be removed from specific accounts in the utility's ASC filings.[336] To achieve this, the Public Power customers suggest modifying the Senior Financial Officer Attestation to require IOUs to certify that their Base Period ASC excludes costs disallowed by any regulatory body with jurisdiction over retail or wholesale rates in the region.[337] They assert that ratepayers should not subsidize costs excluded from retail rates, and that equity investors in IOUs accept regulatory risk for higher returns, including the prospect of unrecoverable costs.[338] Public Power customers point to annual reporting requirements from the WUTC and OPUC as tools to support this analysis, advocating for the use of existing state reporting to avoid a burdensome jurisdictional approach.[339] While acknowledging that not all states have these reports, the Public Power customers believe that alternatives can be found, citing the Idaho Public Utilities Commission's (IPUC) similar use of historical test periods and requirements for utilities to adjust for disallowances.[340] They also note that their proposed attestation would place the initial burden on the exchanging IOU to interpret rate settlements for retail rate adjustments, and that BPA can leverage this requirement to ease administrative burden.[341] The Public Power customers urge BPA to amend the ASCM to eliminate disallowed costs from utilities' ASCs, or, alternatively, ensure that no party's ability to propose material adjustments to an IOU's FERC accounts based on state commission adjustments is foreclosed.[342]

AWEC makes similar arguments in its comments.[343]

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[334] 2026 ASCM § 301.4(d).
[335] Public Power Comments (April) at 12.
[336] *Id.*
[337] *Id.*
[338] *Id.* at 12-13.
[339] *Id.* at 13.
[340] *Id.*
[341] *Id.*
[342] *Id.*
[343] AWEC Comments (April) at 2-4.

Evaluation of Positions

Public Power customers and AWEC request BPA move beyond the data and information in a utility's FERC Form 1 and look to state jurisdictional filings to ensure no "disallowed" costs are included in a utility's ASC. Because such an approach draws the ASCM closer to a "jurisdictional" approach to ASCs, BPA provides a brief overview of why it previously decided to move away from that approach.

1. *Background on Why the 2026 ASCM Uses the FERC Form 1.*

As described in section 3.3.1 of this ROD, one of the foundational changes made in the 2008 ASCM from the 1984 ASCM was to change the source of data for a utility's ASC from jurisdictional rate filings to the FERC Form 1. This change substantially improved the efficiency and manageability for the REP. Under a "jurisdictional" approach to ASC formation, BPA must rely on the utility's state commission filings and orders for the source of data used in calculating the utility's average system cost of resources. The problems of the jurisdictional approach were detailed in the 2008 ASCM ROD.[344] Obtaining and reviewing state jurisdictional filings and orders proved to be "inefficient, cumbersome, and extremely contentious. . . ."[345] The problems with the jurisdictional approach largely arose because of three key areas: (1) volume of filings; (2) opacity of orders and filings; and (3) timing of filings.

The volume of filings occurred because every time a utility sought to change its retail rates (whether through a general rate case or an automatic adjustment clause), such a filing would trigger an ASC review by BPA under the ASCM. Considering that some utilities operate in multiple states and jurisdictions, BPA was, at times, reviewing up to 20 ASC filings simultaneously.[346]

The opacity of the state jurisdictional information was another issue. State public utility proceedings are long and complicated. While a utility may file a revenue requirement and other types of information BPA is familiar with, the resulting rate orders may not clearly articulate the basis for the rate change. This is because state regulators must balance the interests of ratepayers and shareholders. Settlements, compromises, and other tradeoffs made during the state public utility proceedings may render it difficult to determine what costs were approved in the final rate order. Additionally, each jurisdiction approaches retail ratemaking filings differently, with different requirements, documentation, and approaches to retail rate orders. Given these differences, and because of the lack of detailed information in some of the orders, in the 1980s and early 1990s, BPA increased its Staff and intervened in the utility's state retail processes to ensure it could see what cost information was being approved in state commission orders. This approach greatly expanded the cost and complexity of the ASC reviews, with BPA ASC review staff once exceeding over 40 employees.[347]

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[344] 2008 ASCM ROD at 6-9, 11, 16
[345] *Id.* at 16.
[346] *Id.* at 6.
[347] By comparison, BPA's current ASC staff and related support is roughly 8 personnel.

The varying timelines of state proceedings introduced additional complexities. Utilities do not have a fixed schedule for reviewing their retail rates, and this schedule rarely aligns with how BPA sets its own rates. Consequently, utilities might adjust their retail rates before, during, or after BPA finalizes its power rates. This misalignment caused discrepancies between the ASC BPA used when setting its rates and the actual data used to calculate a utility's ASC during BPA's rate periods. These discrepancies meant that BPA's forecasted REP payments could differ considerably from actual payments, as the utility's ASC deviated from BPA's forecast. Further complicating matters, jurisdictional delays in retail rate orders could introduce additional separation. For example, BPA would initially bill a utility based on its "as filed" ASC, which would later be adjusted to the ASC BPA ultimately approved, leading to additional variations and subsequent debits and credits for the utilities.[348]

All three of these issues were largely resolved when BPA elected, in 2008, to use the FERC Form 1 as the basis for the cost and load information for the utility. The FERC Form 1 provided a uniform way to review all utility (IOU) data in one format, on a consistent cadence, that corresponded to the commencement of a BPA rate case. The FERC Form 1 is filed by all IOUs with FERC in April of each year, so the ASCM sets the timing of ASC filings to follow BPA's rate cases.[349] BPA's job of reviewing ASCs also became simpler. Because the data in the FERC Form 1 is historical, actual data, disputes over what resource costs were being permitted into the utility's ASC reduced significantly. And, to that point, while the jurisdictional approach resulted in multiple disputes both at FERC and in the Court, BPA's implementation of the ASCM through the FERC Form 1 has been largely non-controversial.

While the FERC Form 1 is the primary source of data, the 2008 ASCM requires the utilities to provide state jurisdictional information for certain areas. Thus, for instance, BPA requires utilities to supply regulatory orders for FERC Form 1 accounts with regulatory assets in them.[350] A similar requirement is applied to the equity return for IOUs and federal income taxes.[351]

The 2026 ASCM retained these features of the 2008 ASCM and included additional accounts subject to the requirement that a jurisdictional order be provided.[352]

2. *Public Power Customers' Request for Removing Disallowed Costs*

The Public Power customers contend that the FERC accounts allow in "disallowed" costs by state regulators for IOUs.[353] The Public Power customers note that the FERC Form 1 "is a financial accounting record, not a ratemaking document," and as such it may contain disallowed costs.[354] The Public Power customers note that if the costs included in an IOU's

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[348] *See CP National v. BPA*, 928 F.2d 905, 909 (9th Cir. 1991).
[349] 18 C.F.R. § 141.1(b)(2)(ii).
[350] 2008 ASCM ROD at 149-150.
[351] *Id*. at 24-26.
[352] *See* section 5.8.6 of this ROD (Injuries and Damages), and *Issue 5.8.6.1.1*.
[353] Public Power Comments (April) at 12.
[354] *Id.*

FERC Form 1 differ from the costs permitted by the IOU's regulatory commission for the applicable test period for retail ratemaking, these disallowed costs should be identified and removed from specific accounts in the utility's ASC filings as appropriate.[355] To achieve this, the Public Power customers suggest that BPA modify the Senior Financial Officer Attestation to require the IOU to attest that it excluded from its Base Period ASC any costs "disallowed by any Regulatory Body(ies) with jurisdiction to approve retail or wholesale rates in the region."[356]

AWEC makes a similar comment.[357] While supporting the continued use of the FERC Form 1 in the ASC, AWEC contends removing disallowed costs is consistent with the purpose of the Northwest Power Act and places "residential and small farm customers of IOUs and COUs on comparable footing."[358] AWEC notes that the FERC Form 1 does not exclude costs disallowed by state regulators of a utility.[359] Including disallowed costs in a utility's ASC "create[s] disproportionate benefits for IOU ratepayers at the expense of COU ratepayers."[360] While recognizing the desire for a "streamlined approach to evaluating each utility's ASC" and a "hesitance to return to the more resource-intensive jurisdictional approach" AWEC urges BPA to look beyond the FERC Form 1 to determine a utility's ASC.[361]

As BPA understands the comments of Public Power customers and AWEC, neither party is requesting BPA to abandon the FERC Form 1 and return to the jurisdictional approach in the 2026 ASCM. Rather, they both seek to make the exchanging utilities convert their FERC Form 1 data into quasi-jurisdictional data, tying the FERC Form 1 data to retail rate making decisions that approved the underlying cost. If a cost was disapproved by state regulators, then the corresponding cost would be excluded from ASC.

While BPA understands these entities' desire to ensure a close relationship between a utility's ASC and the rates paid for by retail consumers, BPA disagrees that making this adjustment is warranted. Adjusting the 2026 ASCM in the manner suggested by Public Power customers and AWEC would, effectively, be returning the ASCM to a "jurisdictional" approach. As discussed above, BPA had sound reasons not to continue that approach in the 2008 ASCM and reaffirms here those reasons to retain a FERC Form 1 approach without a reliance on jurisdictional filings (except in limited circumstances).

Public Power customers and AWEC suggest that BPA could impose the jurisdictional requirements without additional burden by using existing state public utility filing information.[362] The Public Power customers note that both the WUTC and OPUC have

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355 *Id.*
356 *Id.*
357 AWEC Comments (April) at 2-4.
358 *Id.* at 2.
359 *Id.*
360 *Id.*
361 *Id.*
362 Public Power Comments (April) at 13; AWEC Comments (April) at 3.

annual reporting requirements that can be used to support the analysis they seek.[363] The Public Power customers state these existing reporting requirements should be utilized, avoiding the need for BPA to revert to a burdensome jurisdictional approach.[364]

BPA does not see how this burden would be alleviated based on state-mandated reporting requirements. Indeed, in many respects, BPA sees these requirements multiplying its burden. The information required to be included in the Oregon "Annual Report Requirements" appears to be different from the requirements for Washington's Commission Basis Report.[365] The Commission Basis Report for the WUTC also appears to have a normalizing feature, in that it states its purpose is to "depict the electric operations of an electric utility under normal temperature and power supply conditions during the reporting period."[366] The Oregon Annual Report Requirement also lacks any reference to the FERC Form 1, leaving it to BPA to determine how to translate this report into usable information for the Appendix 1 and ASC calculations.[367] The Montana Public Service Commission requires an annual filing from its utilities, but its form expressly *prohibits* the utility from using FERC Form 1 data sheets in lieu of the required state form.[368] The Idaho Public Utilities Commission has a form that appears to be similar to the FERC Form 1, and thus, is the only commission to have a form that could be readily used in the kind of evaluation suggested by the Public Power customers.[369]

Given the multiplicity of filings, requirements, and regulations, BPA's concern with the burden imposed by Public Power customer's recommendation still stands. BPA would have to become conversant in each state's reporting requirements, including (1) what each state's report shows; (2) what each state's report does not show (or shows in a manner not compatible with the ASCM); (3) how to translate both (1) and (2) to the FERC Form 1 and, ultimately, to the Appendix 1. For these reasons, BPA sees its administrative burden increasing, not decreasing, under this paradigm.

The answer of Public Power customers and AWEC to this issue is that the "initial" burden would fall on the IOUs through modifying the utility's attestation requirements.[370] That may be. But that burden would not stay there. States are not responsible for determining a utility's ASC pursuant to the ASCM, and therefore, their regulations and reporting requirements are ill suited for that task. It is, instead, BPA's duty under the Northwest

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[363] Public Power Comments (April) at 13.
[364] *Id.*
[365] *Compare* PGE Regulated Results of Operation for 2024, at i-vii, May 1, 2025 (describing Results of Operation Report), *available at* https://edocs.puc.state.or.us/efdocs/HAQ/re119haq336523034.pdf; *with* WAC 480-100-257 (Commission basis report requirements).
[366] WAC 480-100-257(2).
[367] *See* PGE Regulated Results of Operation for 2024, Attachment 1 at 1-12, May 1, 2025.
[368] *See* Annual Report, Cover Sheet Instructions, Montana Public Services Commission, at iii, *available at* https://psc.mt.gov/_docs/Archived-Reports/Regulatory-Annual/forms/2009ElectricCoverSheetandTOC.pdf ("FERC Form-1 sheet may not be substituted in lieu of completing annual report schedule.")
[369] *See for example*, Avista Corp, 2025 Idaho State Electric Annual Report, *available at* https://puc.idaho.gov/Fileroom/PublicFiles/MULTI/AVU/General/0Annual%20Report/2025Idaho%20State%20Electric%20Annual%20Report.pdf.
[370] Public Power Comments (April) at 13; AWEC Comments (April) at 2-4.

Power Act to "determine[]" each utility's ASC.[371] BPA must do that, in turn, based on the ASCM. Thus, no matter the state form the utilities may have available to distill information, the task of ensuring that only resource costs consistent with the ASCM are included in a utility's ASC will fall on BPA. Ultimately, BPA would have to be involved in checking to ensure that the costs included in its FERC Form 1 have been approved by the respective jurisdictions for the period in question. This would inevitably lead to BPA pulling and reviewing utility filings in state proceedings, and may eventually result in BPA intervening in those proceedings to determine whether the state commission approvals match the numbers in the FERC Form 1 (and in the Appendix 1 of the ASCM). The complexity, difficulty, and contentiousness of the ASCM process would increase exponentially for no discernible additional benefit. In short, BPA does not see how it could impose the requirements that these parties seek without turning the clock back to the "jurisdictional" approach used in the 1981 and 1984 ASCMs. The Public Power customers argue that REP payers should not subsidize costs that have been excluded from retail rates.[372] The Public Power customers contend that equity investors in IOUs accept regulatory risk for higher returns, including the prospect of unrecoverable costs.[373] If IOUs incorporate an inflated weighted cost of capital in ASC development, then regulatory orders safeguarding ratepayers should also be fully incorporated.[374] The Public Power customers note that because BPA's proposed escalation codes increase certain accounts, the ASCM omits the downward adjustments regulators take to "protect ratepayers."[375]

Public Power customers' contention that the utility's higher return for investors offsets the prospect of unrecoverable costs is an oversimplification. While a ROE is risk informed, it does not represent an "equity inflated weighted cost of capital," as alleged by Public Power.[376] A ROE is informed by the *Hope* and *Bluefield* standards of capital attraction and comparable earnings to reasonably approximate what an investor would expect on an investment of comparable risk elsewhere in the economy.[377] But, while risk informs ROE calculations, the calculation does not simply reflect a risk of incurred costs being disallowed as imprudently incurred. Instead, for example under a Discounted Cash Flow (DCF) method, the main factor is the growth forecast. Under a Capital Asset Pricing Model, risk is included in the Beta component based on the stock's volatility compared to a broad market portfolio. The risk of disallowed costs is not the only risk to revenue volatility. Load, weather, and market prices all affect the returns investors will experience. As explained in *Issue 5.6.1*, the complexity inherent in determining a return on equity makes it unlikely that one would be able to isolate the risk of disallowed costs on an approved ROE level, and BPA is unaware of such precision being applied at the state level. Thus, BPA does not agree that, simply because a cost *could* be disallowed at the state level, the utility is

[371] 16 U.S.C. § 839c(c)(7).
[372] Public Power Comments (April) at 12.
[373] *Id.*
[374] *Id.* at 12-13.
[375] *Id.* at 13.
[376] *Id.* at 12.
[377] *See Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works v. Public Service Comm'n,* 262 U.S. 679 (1923) ("*Bluefield*").

being compensated through its return on equity for that risk, such that it would be arguably appropriate to remove disallowed costs from ASC.

This is not to say that BPA finds that all costs included in the FERC Form 1 must blindly be included in a utility's ASC. As noted earlier, for certain cost categories BPA has imposed additional documentation, including regulatory documentation approving of certain costs. BPA imposes these requirements sparingly, and only on accounts that could significantly impact the utility's ASC without corresponding proof that the cost was incurred and assessed to ratepayers. Thus, for instance, under the 2008 ASCM, BPA imposed a jurisdictional-like requirement on a utility's ability to include in its ASC regulatory assets and liabilities because "[f]or some utilities, [regulatory assets and liabilities] represent a significant amount of costs in the FERC Form 1."[378] BPA is imposing a similar requirement on Account 925 – Injuries and Damages, given its potentiality to substantially impact a utility's ASC.[379] BPA is also required by statute to exclude terminated plant costs,[380] whether or not the state regulators choose to disallow such costs as imprudently incurred or not used and useful. FERC Form 1 inputs will be subject to review to ensure the costs are recorded in the appropriate accounts and functionalized appropriately.[381] Further, to the extent Public Power customers and AWEC are concerned with disallowed Transmission costs—either the cost of rebuilding after wildfires or regional buildout—these are not inputs into the draft ASCM.

In the alternative, the Public Power customers contend BPA must not "foreclose" any party's ability to propose material adjustments to an IOU's FERC accounts based on Washington's Commission Basis Reports and similar state commission required adjustments.[382] BPA notes that the information cited by Public Power customers may be appropriate to modifying a value in a utility's FERC accounts *if* such account is one where commission approval is a precondition of its inclusion in ASC. Thus, the cited information may be of use in the context of Account 925 or in determining whether a regulatory asset has or has not been allowed. Additionally, BPA retains the ability to evaluate FERC accounts to ensure they include appropriate costs.[383] Thus, for instance, if a FERC account is supposed to include fuel costs, BPA can make an independent determination of whether the utility has included only fuel costs in that account. If it turns out the utility included some other costs in that account, such as corporate car fleet costs, BPA could remove those costs under the terms of the ASCM. Outside of those types of situations, though, BPA would not agree that a utility may attempt to reinsert a "jurisdictional"-type approach through the ASC review process for each FERC account.

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[378] 2008 ASCM ROD at 150.
[379] *See Issue 5.8.6.1,* (Injuries and damages).
[380] 16 U.S.C. 839c(c)(7)(C).
[381] *See* 2026 ASCM, Pt. II, ASC Procedures at § 3.2.2 ("In calculating ASCs, BPA will make an independent determination of (1) the appropriateness of the inclusion of costs; (2) the reasonableness of the costs included in Contract System Costs; and (3) the appropriateness of Contract System Loads.")
[382] Public Power Comments (April) at 13.
[383] *See* 2026 ASCM, Pt. II, ASC Procedures at § 3.2.2.

BPA recognizes that since 2008, the ASCM has not perfectly matched the costs and credits allowed by state regulators in state proceedings. That level of precision, however, is not required. Section 5(c) is not designed to create perfect parity in retail rates, but to provide a measure of parity with BPA's rates at the wholesale level. Congress understood that costs at the retail level will not be the same. As noted in the House Report (Commerce) in reference to the Section 5(c) exchange: "The requirement is not likely to result in parity in the retail rates being paid by consumers of preference customers and consumers of investor-owned utilities, but it should equalize the wholesale costs of the electric power with a resulting benefit [to] the investor-owned utilities' customers."[384]

Further, BPA's experience with FERC-jurisdictional ratemaking has been that the presumption of prudency renders disallowed costs an exceedingly rare occurrence. The very real day-to-day complexity, burden, opacity, and conflict of a more jurisdictional approach is not justified by the rare potential for disallowed costs. BPA finds it has struck the proper balance here by retaining its general approach to using FERC Form 1 data as the basis for a utility's ASC, with only select accounts subject to regulatory approval.

Draft Decision

BPA will not modify the 2026 ASCM to require utilities to remove from their FERC Form 1 costs disallowed by state regulators.

[384] H.R. Rep. No. 976 (Part I), 96th Cong., 2d Sess. 60 (1980).

4.0 APPLICABILITY, DEFINITIONS, FILING PROCEDURES (CFR § 301.1-3)

4.1 Applicability (CFR § 301.1)

Part I of the 2026 ASCM is the FERC regulation that establishes the terms that apply to the calculation of a utility's average system cost of resources for sales of electric power to BPA under Section 5(c) of the Northwest Power Act. Section 301.1 establishes the scope and purpose of the ASCM as well as its statutory basis.

4.2 Definitions (CFR § 301.2)

Section 301.2 contains the definitions that apply to the terms of the 2026 ASCM. Following the posting of the February 2026 draft ASCM for formal comment,[385] BPA discovered that it had used various terms to refer to Public Power customers throughout the methodology. In some instances, BPA referred to them as Public Customers, and in others as Public Utilities. Neither term was defined. To address this ambiguity, BPA removed these varying references and added the term "Public Power Entity" to the definition section.[386] BPA discussed these changes at the July 31, 2026, workshop.[387]

4.2.1 Issues

<u>Issue 4.2.1.1</u>

Whether BPA's deletion of the term "Priority Firm Power" from the 2026 ASCM is reasonable.

<u>BPA Staff's Proposal</u>

BPA Staff proposed to delete the term "Priority Firm Power" from the 2026 ASCM because the term is not used in the 2026 ASCM.

<u>Parties' Positions</u>

The IOUs assert that the term "Priority Firm Power" is a "critical term in the context of the REP and should remain in the ASCM."[388] The IOUs claim that the definition of "Priority Firm Power" supports the IOUs' position that the REP involves a physical, rather than a purely financial, exchange, and the IOUs disagree with BPA's alleged "inappropriate and pretextual deletion of the definition."[389]

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[385] *See* 2026 ASCM Draft for Formal Comment, Clean, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260220-2026-ascm-draft-for-formal-comment-clean.doc.
[386] *See* 2026 ASCM § 301.2 (definition of "Public Power Entity").
[387] *See* ASCM Workshop 7, at 9, July 31, 2026.
[388] IOU Comments (April) at 13.
[389] *Id.*

Evaluation of Positions

In the 2026 ASCM, BPA removed the term "Priority Firm Power" from the definitions in § 301.4 of the ASCM because the term is no longer used. It is not necessary to define a term that is not used in a document. Under the 2008 ASCM, Public Power customers were required to limit their participation in the Section 5(c) exchange to only specific resources and for certain limited loads.[390] That limitation is effectuated through references to certain technical terms from the Tiered Rates Methodology (TRM), which only applies to Public Power customers. Thus, for instance, the phrase "Priority Firm Power" is used in the 2008 ASCM only in the context of the definition of "RHWM System Resources," which is a technical defined term from the TRM.[391] The term was included only because it was used in determining ASCs of participating Public Power customers – it served no other purpose. The term "RHWM System Resources" does not appear in the 2026 ASCM because the "limited" participation model for Public Power customers has been removed. Instead, Public Power customers either waive their participation in the REP in its entirety or participate on the same footing as IOUs.[392] Because the RHWM System Resources term was removed, BPA also removed the definition of "Priority Firm Power" from the 2026 ASCM. Far from being a "critical term,"[393] the term "Priority Firm Power" is not used anywhere in the 2026 ASCM.

The IOUs object to the deletion of the term "Priority Firm Power" from the ASCM, arguing that it reflects that BPA is obligated to make "electric power (capacity and energy) . . . continuously available for direct consumption or resale to . . . [u]tilities participating in the Residential Exchange Program," and that "[u]tilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act may purchase Priority Firm Power under their Residential Purchase and Sale Agreements with Bonneville."[394] The IOUs also claim this definition observes that "deliveries" of such power may be reduced

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[390] *See* 18 C.F.R. § 301.4(g).

[391] *See* 18 C.F.R. § 301.2:

> RHWM System Resources. The Rate Period High Water Mark (RHWM) as calculated in section 4.2.1 of the Tiered Rates Methodology plus the resource amounts used in calculating a customer's Contract High Water Mark (CHWM).
>
> Tier 1 Priced-Power. **Priority Firm Power** as defined in Bonneville's Tiered Rates Methodology.
>
> Tier 1 System Resources. Resources as defined in Bonneville's Tiered Rates Methodology.

(Emphasis added).

[392] Public Power customers have waived their right to participate in the REP during the term of the Provider of Choice (POC) contract (FY 2028-2044). *See* Provider of Choice (POC) Policy § 10.1 (Mar. 21, 2024), ("POC Policy") *available at* https://www.bpa.gov/-/media/Aep/power/provider-of-choice/provider-of-choice-policy-march-2024.pdf. *See also* Bonneville Power Administration, Provider of Choice Policy, Administrator's Record of Decision at 294-301(Mar. 21, 2024) ("POC Policy ROD"), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf.

[393] IOU Comments (April) at 13.

[394] *Id*. at 12-13, *citing* 18 C.F.R. § 301.2.

or interrupted only as permitted by the RPSA with BPA.[395] The IOUs claim this definition is relevant to "the question as to whether Section 5(c) of the NWPA requires BPA to implement REP purchase and exchange sales as physical transactions."[396]

BPA disagrees that the definition of "Priority Firm Power" should be retained in the 2026 ASCM. The term "Priority Firm Power" is not used anywhere in the 2026 ASCM so deleting it from the methodology is entirely reasonable. BPA does not see the logic in retaining the term "Priority Firm Power"—a term not used in the 2026 ASCM—when BPA has deleted other terms from the 2008 ASCM that are also not used.[397]

BPA also finds unconvincing the IOUs' claim that the definition of the term "Priority Firm Power" supports their view that the REP was intended to be implemented as a physical purchase and sale.[398] The terms of the ASCM do not establish the manner in which the REP is to be implemented, but the "'average system cost' for electric power sold to the Administrator."[399] The terms for implementing the purchase and sale feature of the REP, as the IOUs are aware, are provided for in the Residential Purchase and Sale Agreement (RPSA). The 2008 ASCM ROD is clear on this point: "The REP is implemented through Residential Purchase and Sale Agreements, which are contracts between BPA and each exchanging Utility."[400] In any event, the 2008 RPSA did not involve physical deliveries, so it is unclear what import this language had even at the time it was in the 2008 ASCM.[401]

In short, BPA sees no reason to retain the term "Priority Firm Power." It was not used in the body of the 2008 ASCM, but was instead embedded in another term that did not apply to the IOUs, and had a very narrow application. BPA has separately addressed the IOUs' arguments regarding the operation of the Section 5(c) exchange and does not revisit that issue here.[402]

Draft Decision

BPA's decision to delete the term "Priority Firm Power" from the 2026 ASCM is reasonable.

4.3 Filing Procedures (CFR § 301.3)

BPA developed a separate procedural document detailing the process, timeline and requirements for utilities to participate in ASC Review filings, generally referred to as the ASC Review Rules of Procedure for BPA's ASC Review Processes (ASC Procedures). The

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[395] *Id*. at 13.
[396] *Id*. at 13.
[397] *See e.g., Preliminary Draft 2026 Average System Cost Methodology, redline version,* at 2-6 (Dec. 10, 2025), (showing deletion of "RHWM Exchange Load", "RHWM System Resources", "Tiered Rates Methodology", "Rate Period High Water Mark Process", "Rate Period High Water Mark", "Contract High Water Mark.")
[398] IOU Comments (April) at 13.
[399] 16 U.S.C. § 839c(c)(7).
[400] 2008 ASCM ROD at 161.
[401] 2026 RPSA ROD at 62-63, (Mar. 6, 2026) *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2026-rod/rod-20260306-2026-residential-purchase-and-sale-agreement-record-of-decision.pdf.
[402] *See generally,* 2026 RPSA ROD.

ASC Procedures are found in Part II of the ASCM and provide descriptive instruction for the documents comprising a utility's filing for the purpose of establishing an ASC and qualifying for REP benefits. The ASC Procedures detail each step of the ASC Review process, which runs parallel to BPA's rate case proceedings and provides a schedule for the process. The ASC Procedures include the terms for utilities to provide both formal ASC filings and "informational" ASC filings in years when formal ASC filings are not submitted.

Section 301.3(a) highlights the documents required in an ASC filing. These consist of a fully populated Appendix 1 Excel workbook, supporting documentation of accounts functionalized by Direct Analysis, calculation of distribution losses, rate of return calculation, new resources projected to become operational after the Base Period, and calculation of costs to serve NLSLs. The filing also consists of a pre-run Excel model (ASC Forecast Model), a variance analysis comparing the Base Year data with prior calendar year data, and the utility's signed Senior Financial Officer Attestation.

Section 301.3(b) makes clear that the Exchange Period will follow the same term as BPA's Rate Period and will only change for the reasons noted in § 301.5.

Section 301.3(c) addresses filing requirements for a utility that has had a change in service territory. In the previous versions of the ASCM, this section was embedded in § 301.5(g). BPA moved it to this section to keep topically related materials together.[403]

[403] *See* ASCM Workshop 7, July 31, 2026, at 10.

5.0 BASE PERIOD AVERAGE SYSTEM COST (CFR § 301.4)

5.1 Overview

An ASC represents a participating utility's average costs of its generating resources, as defined by Sections 5(c)(1) and (7) of the Northwest Power Act, represented as a dollar per megawatt-hour rate. The Base Period is the historical calendar year of the utility's most recently filed/published FERC Form 1 data available at the start of the ASC review process. The Base Period ASC represents a utility's historical average system cost of resources, which serves as the basis for establishing its Exchange Period ASC and REP benefits. Section 301.4 establishes the provisions used to determine a utility's Base Period ASC.

5.2 Appendix 1 Purpose and Source Data (CFR § 301.4(b)-(f))

5.2.1 Appendix 1 – Overview

The Appendix 1 reflects the FERC Form 1 accounts listed in Table 1, supplemented by information sourced from the utility's state commission rate filings and operational data for its weighted costs of capital and distribution losses. The utility sources the data populated in the Appendix 1 from its most recently published FERC Form 1, state commission rate orders, and internal operational data. FERC accounts comprise Schedules 1, 1A, and 3-4. State commission orders provide data on the utility's weighted costs of capital (rate of return and costs of capital) populated in Schedule 2. In addition, utility operational data is required for the distribution loss calculation tab if utilities apply Method 1 – distribution loss studies.

These values (and all subsequent values) are entered into the Appendix 1 as line items based on FERC's Uniform System of Accounts, where applicable. Each line item (Account) is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalization prescribed in Table 1 of the ASCM.

As noted previously, under the 2008 ASCM, BPA moved away from jurisdictional costing as the data source for Appendix 1s and instead adopted utilities' FERC Form 1s. Sourcing from FERC Form 1s created uniformity in Appendix 1 utility data and streamlined the ASC review process. The 2026 ASCM retains sourcing from utilities' FERC Form 1s.

BPA added the ability to revise and add new FERC accounts to Table 1 and the Appendix 1 without undergoing a consultation process under § 301.6(d) of the 2026 ASCM. Under the 2008 ASCM, the provisions allowed BPA to update or renumber FERC accounts but precluded adding accounts.

5.2.2 Appendix 1 - Template

The Appendix 1 template is comprised of several tabs and schedules in an Excel workbook, each of which implements different components of the 2026 ASCM to calculate a utility's ASC. The following is a high-level overview of the primary components:

5.2.2.1 Schedule 1: Plant Investment/Rate Base

This tab establishes the utility's Rate Base, which is the value of property on which the utility is permitted to earn a specific rate of return as approved by its state's Public Utility Commission.

The Rate Base computation is based on the utility's Net Electric Plant-In Service (Gross Electric Plant-In-Service's historical costs for Intangible, General, Production, Transmission, and Distribution Plant less functionalized depreciation and amortization reserves) adjusted for Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and Deferred Credits.

Utilities with electric, natural gas, and water services will only include in their Appendix 1 the electric portion of common plant allocated.

5.2.2.2 Schedule 1A: Cash Working Capital

Cash working capital is an estimate of investor-supplied cash used to finance operating costs during the time lag before revenues are collected. The Cash Working Capital calculation ignores the lag in recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The Cash Working Capital concept is widely used by state commissions and is the basic premise of the commissions' proposed working capital formula. The purpose of working capital is to compensate a utility for funds used in day-to-day operations.

Cash Working Capital is a ratemaking convention that is not included in FERC's Uniform System of Accounts but is part of all electric utility rate filings as a component of Rate Base.

BPA allows one-eighth (1/8) of the functionalized costs of total production expenses, transmission expenses, and administrative and general expenses, less purchased power, fuel costs, and public purpose charges, for Cash Working Capital into Rate Base.

5.2.2.3 Schedule 2: Capital Structure and Rate of Return

Schedule 2 calculates the utility's rate of return (ROR) based on the utility's Schedule 1: Rate Base.

The ASCM requires the use of the weighted cost of capital (WCC) from the utility's most recent state commission rate order. The return on equity (ROE) used in the WCC calculation is grossed up for federal income taxes at the marginal federal income tax rate using the formula described in the ASCM.

5.2.2.4 Schedule 3: Expenses

This schedule represents operations and maintenance (O&M) expenses for the production, transmission, and distribution of electricity. Each expense item is functionalized as outlined in Table 1 of the ASCM. Also included in Schedule 3 are additional expenses associated with customer accounts, sales, administrative and general expenses (A&G), conservation program expenses, and depreciation and amortization expense associated with Electric Plant-in-Service. The sum of the items in Schedule 3 reflects the Total Operating Expenses for the utility.

5.2.2.5 Schedule 3A: Taxes

This schedule comprises allowable ASC costs for federal employment taxes and certain non-federal taxes, including property and unemployment taxes. State income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this schedule but are functionalized to Distribution/Other and therefore not included in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 purposes.

Federal income taxes calculated in Schedule 2 – Capital Structure and Rate of Return are included in ASC.

5.2.2.6 Schedule 3B: Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity for others (wheeling). The revenues in this schedule are deducted from the total costs of each utility.

5.2.2.7 Schedule 4: Average System Cost

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, Taxes, and Other Included Items. The schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the Utility's Base Period ASC ($/MWh).

Contract System Cost (CSC) ($)

CSC includes the utility's costs for production resources, including power purchases and conservation measures, which are includible in and subject to the provisions of the ASCM. CSC does not include Transmission or Distribution/Other costs or the cost of serving a utility's NLSLs. CSC is the numerator in the ASC calculation.

Contract System Load (CSL) (MWh)

CSL is the total regional retail load of a utility, adjusted for distribution losses and NLSLs. CSL is the denominator in the ASC calculation.

5.2.2.8 Other supplemental tabs required for the calculation of the Utility's ASC.

The Appendix 1 has numerous supplemental tabs used for calculating a utility's ASC pursuant to the 2026 ASCM. These include: *Purchased Power and Sales for Resale, Load Forecast, Distribution Loss Calculation, Distribution of Salaries and Wages, Ratios, New Resources- Individual and Grouped, Materiality for New Resource Additions – Individual and Grouped, and New Large Single Loads.*

5.3 Affiliated Companies and Multi-Jurisdictional Entities (CFR § 301.4(g)-(i))

The ASCM will calculate a single ASC for Affiliated Companies and Multi-jurisdictional Entities, and such utilities must file a combined or single Appendix 1.

Affiliated Companies (g)

Utilities with affiliated, associated, subsidiary companies, including parent and special purpose or holding companies owned in whole or in part by the Utility will be considered one utility. Intercompany transactions will be excluded from the utility's ASC. Such utilities must file a combined Appendix 1 and a single ASC will be calculated. Utilities will report investments in affiliated and subsidiary companies in FERC accounts 123 and 123.1 respectively.

Multi-jurisdictional Entities (h)-(i)

Utilities that serve retail customers in more than one state jurisdiction, within or outside of the Pacific Northwest region, will aggregate in-region system-wide costs and load to a single Appendix 1.

5.4 Functionalization Codes, Requirements, and Methods (CFR § 301.4(j)-(m))

Table 1 assigns functionalization codes to each account to prescribe its allocation in whole or in part to Production, Transmission, Distribution or any combination of the three. Section 301.4(j) lists the various functionalization codes which are computed in the Ratios tab of the Appendix 1 based on the proportional costs of each business function.

Accounts with an option for Direct Analysis offer utilities discretion to functionalize costs manually or, where applicable, by using a ratio. Combining the use of Direct Analysis and a ratio is not permitted. Use of Direct Analysis requires utilities to submit detailed documentation that supports the reasoning for costs functionalized to Production. Failing to provide sufficient documentation may result in BPA assigning the costs. The requirements for a Direct Analysis are outlined in § 301.4(m).

Supporting documentation for costs functionalized by Direct Analysis to Production in regulatory assets and liabilities, and deferred debits and credits accounts on Schedule 1 must demonstrate approval for rate-recovery in a state commission rate order. Injuries and Damages costs in Account 925 and the associated Commission Approved Injuries & Damages account on Schedule 3 have a similar requirement, see § 301.4(w).

Conservation-related costs are assigned to Production regardless of the account in which they are recorded. Utilities may use Direct Analysis on any account that contains conservation-related costs. The subject utility must adhere to the requirements for providing detailed supporting documentation. Advertising and promotion costs related to conservation must be functionalized by Direct Analysis.

5.5 Distribution Losses and Study (CFR § 301.4(n))

Distribution losses, measured in megawatt-hours, gross up a utility's Contract System Load. The 2026 ASCM provides two methods to calculate distribution losses for ASC input: 1)

Method 1, Distribution Loss Study, and 2) Method 2, Default. Under Method 1, utilities may submit a published Loss Study which is valid for ASC purposes for up to seven years after its publication date. The seven-year timeframe is a rollover from the 2008 ASCM. Alternatively, under Method 2 utilities may utilize load data from their FERC Form 1 to calculate a five-year total system load factor. Method 2 is also a rollover from the 2008 ASCM. The description of Method 2 was updated to reflect BPA's weighted seasonal transmission system losses into a single loss factor.

5.5.1 Issues

Issue 5.5.1.1

Whether BPA should limit utilities to a single method for determining Distribution Losses in the 2026 ASCM.

BPA Staff's Proposal

The 2026 ASCM permits a utility to use one of two methods for determining its Distribution Losses.[404] Either method is acceptable.

Parties' Positions

Both Public Power customers and AWEC express concern that providing exchanging utilities with options for determining their Distribution Losses will result in the utilities "cherry picking" the method that most benefits them.[405]

Evaluation of Positions

Under the 2008 ASCM, utilities had three methods for determining losses associated with their respective distribution systems to gross up their Contract System Loads.[406] Method 1 allowed the utility to measure losses based on a Distribution Loss Study. Method 2 allowed a utility to measure losses using meter readings, if the utility had revenue grade metering on its distribution system. Method 3 was a "default" method that calculated distribution losses by averaging the utility's total system loss factor over five years and then reducing that loss factor by BPA's transmission system loss factor.

For the preliminary draft 2026 ASCM, BPA proposed to remove two of these methods and limit utilities to a single approach, Method 3 (default).[407] BPA proposed this change because it believed most, if not all, utilities had gravitated to using Method 3 for determining their losses.[408] In their comments on the preliminary draft ASCM, the IOUs informed BPA that most used Method 1 (Distribution Loss Study), while some used Method 3 (Default).[409] Given that the IOUs used both approaches, BPA decided to retain Methods 1

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[404] 18 C.F.R. § 301.4(n)(1)-(2).
[405] Public Power Comments (April) at 7; AWEC Comments (April) at 4.
[406] *See* 18 C.F.R. § 301, Appendix 1, endnote e.
[407] *See* Preliminary Draft ASC, Dec. 10, 2025 at § 301.4(n).
[408] *See* ASCM Workshop 1, at 45, Oct. 23, 2025.
[409] IOU Preliminary comments at 2.

and 3. BPA removed Method 2. No party supports retaining Method 2 (Revenue Grade Meters).

The Public Power customers advocate for a single, standardized method for calculating distribution losses in the ASCM, opposing the draft methodology's two options.[410] They argue that multiple approaches risk inconsistent treatment and selective use to inflate ASC values.[411] Therefore, Public Power customers support using the default calculated distribution loss method exclusively to ensure consistency and transparency across utilities.[412] If Method 1 (Distribution Loss Study) remains a viable option, the Public Power customers recommend that IOUs that use this option be required to update their distribution loss studies before each Exchange Period.[413]

AWEC makes a similar comment, expressing concern that allowing choice enables "cherry-picking" the most advantageous method.[414] Therefore, AWEC recommends that the final ASCM identify "a single method that can be used to calculate distribution losses."[415]

BPA disagrees that limiting a utility's distribution loss calculation to a single method is necessary. The distribution loss adjustment aims to accurately determine the utility's total Contract System Load. Both methods BPA provides in the 2026 ASCM are reasonable, and BPA sees no basis to conclude that one is superior to the other. Initially, BPA proposed a single approach, believing that all IOUs were already moving towards a particular method. For administrative simplicity, a unified distribution calculation method would have been beneficial. However, BPA now recognizes that not all utilities must use the same method. As long as the terms of each method are followed, either is appropriate for calculating a utility's ASC.

Additionally, BPA believes that concerns regarding "cherry-picking" one method over the other are overstated. Method 1 (Distribution Loss Study) permits a utility to conduct an engineering, statistical, or other type of "study," which must then be submitted to BPA for "review."[416] Given the scrutiny these studies undergo and their significant production costs, this option will likely be self-regulating. A utility that has invested in such expense and review is unlikely to abandon it merely for a slightly better outcome under Method 3 (Default). Method 3 (Default) is available when a utility does not wish to undertake that expense and review. Method 3 is the "default" approach, which utilizes the previous five years of total system loss factors and then subtracts BPA's own system loss factor.[417]

This experience aligns with BPA's review of utility ASCs. Once a utility conducts a distribution loss study, it typically retains that study for its duration (usually seven years). Under the 2008 ASCM, BPA offered three methods for distribution loss treatment.

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[410] Public Power Comments (April) at 7.
[411] *Id.*
[412] *Id.*
[413] *Id.* at 8.
[414] AWEC Comments (April) at 4.
[415] *Id.*
[416] *See* 2026 ASCM § 301.4(n)(1).
[417] *See* 2026 ASCM § 301.4(n)(2).

Throughout its operation, BPA observed no pattern of IOUs strategically altering methods to 'game' this provision.[418] While utilities occasionally changed their methods, these changes were infrequent and often driven by external factors, such as broader studies the utility was already undertaking.[419] Of the six IOUs that participated in the REP from 2012 to the present, two never changed their method, three changed it once, and one changed it twice.[420] This data does not indicate any evidence of gamesmanship or 'cherry picking' to BPA.

Draft Decision

BPA will retain Method 1 (Distribution Loss Study) and Method 3 (Default) for determining Distribution Losses in the 2026 ASCM.

5.6 Rate of Return (CFR § 301.4(o))

The overall Rate of Return (ROR) applied to the utility's Base Period and Exchange Period ASCs is its weighted cost of capital (WCC) grossed-up by the marginal then in-effect Federal corporate income tax rate. The ROR is calculated and applied to the utility's Production rate base to derive the return on rate base included in its ASC.

Multi-jurisdictional utilities will calculate a WCC for each jurisdiction, apply it to the corresponding jurisdictional rate base and lastly aggregate the return on rate base from each jurisdiction.

5.6.1 Issues

Issue 5.6.1.1
Whether BPA should revise the 2026 ASCM treatment of return on equity in a utility's ASC.

BPA Staff's Proposal

The 2026 ASCM provides that "[t]he overall Rate of Return (ROR) to be applied to a Utility's Exchange Period rate base as shown in Appendix 1 must be equal to its weighted cost of capital (WCC), including debt, preferred stock and equity, from its most recently approved Regulatory Body Rate Order in effect at the time the Utility submits its ASC Filing."[421]

Parties' Positions

Public Power customers argue that if BPA does not exclude wildfire liability and disallowed costs from ASC, then BPA should "reexamine the rate of return" on the IOU capital structure.[422] They contend that the increased risks, including wildfire liability, are already accounted for in the cost of capital.[423] They argue that, if the utility's full return on equity is included in ASC, REP payers "effectively bear both the risk premium embedded in

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418 Distribution Loss Study Election (IOUs), Sep. 11, 2026 (on file with author).
419 *See id*.
420 *Id.*
421 2026 ASCM § 301.4(o)(1).
422 Public Power Comments (April) at 13.
423 *Id.* at 13-14.

authorized return on equity and the realized costs associated with that risk."[424] To prevent this duplicative recovery, Public Power customers suggest BPA reconsider the treatment of return on equity in the ASCM by "incorporating language similar to footnote d/ of the 1984 ASCM, which limited the overall rate of return to be applied to a utility's rate base to an amount equal to the utility's weighted average cost of long-term debt."[425]

Similarly, "[a]s a lesser-preferred alternative" to AWEC's proposal to exclude disallowed costs, "AWEC supports reexamination of the rate of return allowed on IOU capital consistent with the language in footnote d/ of the 1984 ASCM."[426]

Evaluation of Positions

As detailed in the evaluation section below, BPA has revised its proposal regarding the inclusion of return on equity (ROE) in a utility's ASC.

BPA originally proposed retaining the 2008 ASCM approach, which allowed utilities to include their full ROE in their ASC.[427] However, feedback from Public Power prompted BPA to reconsider this position—especially given the decision to exclude transmission asset costs from the ASC, which would be a factor in determining a utility's ROE at the state commission level.[428] Following this re-evaluation, BPA Staff introduced a revised approach during the July 31, 2026, workshop.[429] Under this updated proposal, the ASCM will allow a modified ROE that applies exclusively to non-transmission assets. BPA's decision is to adopt Staff's revised proposal in the 2026 ASCM.

The following discussion addresses:

1. ROE and its application in the Rate Base;
2. The historical treatment of ROE in previous ASCMs; and
3. BPA's approach for the 2026 ASCM, which:

   a. Rejects Public Power's request to eliminate ROE entirely in favor of using only the weighted average cost of debt, and

   b. Limits the allowable ROE for ASC purposes strictly to non-transmission assets.

1. *<u>Overview of Return on Equity and Rate Base</u>*

Under the ASCM, a utility's operation and maintenance (O&M) and administrative and general (A&G) costs are accounted for directly through the FERC Form 1 accounts. The utility's capital asset costs, however, do not directly come into a utility's ASC through the

[424] *Id.* at 14.
[425] *Id.*
[426] AWEC Comments (April) at 4.
[427] *See* 2026 ASCM Draft for Formal Comment, Clean, Feb. 20, 2026, § 301.4(o).
[428] Public Power Comments (April), at 13-14.
[429] ASCM Workshop 7, at 13, July 31, 2026.

FERC Form 1. Instead, these costs are included in its "rate base," which then comes into the ASCM through the "rate of return."

IOU rates are typically determined by a "rate base," which reflects the utility's investment in capital assets—plant, facilities, property, equipment—used by the utility to serve its customers. A public utility commission determines the "fair value" of the rate base, and the "fair return" the utility is permitted to earn on that rate base.[430]

Capital assets in a utility's rate base are generally financed in two ways. The utility may finance its assets with debt. Conversely, the utility may finance them with equity (*i.e.*, stock or cash from the company). The relative balance between these forms of financing is referred to as the utility's "capital structure."

For example, consider a utility that financed 50% of its capital with debt, and 50% with equity. The cost of debt is the average of the actual interest rate on the debt issuances. The cost of equity is the "Return on Equity" approved by the relevant commission. If we assume the cost of debt is 4% and the ROE is 9%, the weighted "rate of return" would be 6.5%.

The "rate of return" is the methodological means for including a portion of a utility's rate base in its ASC. The rate of return is how the utility's Plant capital costs come into a utility's ASC. That is, the product of the rate base and the rate of return is included in ASC. The ROE is a key component of the utility's rate of return.

2. *<u>Prior Approaches to ROE in 1981, 1984, and 2008 ASCMs</u>*

BPA has both included and excluded a utility's return on equity (ROE) in previous ASCMs. In the 1981 ASCM, BPA allowed a utility to include its return on equity as a resource cost with little discussion.

In the 1984 ASCM, BPA recognized that equity investments in a utility were a prudent component of a utility business and lacking equity the utility's investments would "most likely be financed at higher rates."[431] BPA, nevertheless, excluded the ROE from ASC, driven by "serious concern that equity returns allowed by regulatory agencies have indirectly compensated participating utilities for the costs of generating facilities terminated prior to initial commercial operation."[432] That is, BPA was concerned that a utility had attempted to include terminated plant costs (prohibited by the NWPA)[433] by a Public Utility Commissioner artificially inflating the ROE.[434] To avoid future abuses, BPA

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[430] 73B C.J.S. Public Utilities § 45 (2026).
[431] 1984 ASCM ROD at 53 ("Nearly all commenters agree that equity and coverage requirements reduce the risk of debt securities by providing a cushion that absorbs fluctuations in revenues. No one contends that this does not reflect prudent utility practice which benefits both ratepayers and bondholders. Lacking equity support, generation and transmission investments would most likely be financed at higher rates. (<u>See</u>, <u>e.g.</u> OPUC, R. 6581-82). BPA does not dispute this.").
[432] *Id.* at 48 (§ IV.A).
[433] *See* 16 U.S.C. § 839c(7)(C).
[434] 1984 ASCM ROD at 53 ("However, BPA cannot agree that equity returns allowed by regulators do not include, at least tacitly, terminated plant costs and the risks of such terminations. These may well be compensable for ratemaking purposes; however, section 5(c)(7)(C) of the Northwest Power Act prohibits

revised the ASCM to exclude ROE for all utilities.[435] Essentially, the 1984 ASCM addressed this concern by treating the IOU as if its capital program was entirely financed by debt, at its current interest rates. In adopting this proposal, BPA recognized that its "remedy was severe, limiting a Utility's return to the long-term cost of debt."[436]

The IOUs challenged BPA's decision to exclude ROE in the Ninth Circuit. On review, the Ninth Circuit conditionally affirmed BPA's exclusion of ROE from ASC based on BPA's experience with implementing the program and its need to avoid abuses.[437] In making this finding, however, the Court did not "sanction any permanent implementation of these exclusions."[438]

In the 2008 ASCM, BPA concluded that sufficient "changes have occurred in the regional regulatory environment to reasonably ensure that terminated plant costs will not be included with allowable costs under the ASCM."[439] This included most terminated plant costs having been written off, broader governance reforms in state commission processes, and more engagement in utility rate filings by consumer advocate groups.[440] Given these advancements, "the risk that Regulatory Bodies will include inappropriate costs in the ROE has diminished significantly since 1984."[441] Moreover, BPA noted "that the IOUs and state commissions have seen the severe results of a prior attempt to include terminated plant costs in return on equity" and that "BPA does not believe exchanging utilities or commissions would seriously consider undertaking such actions again."[442] Importantly, BPA also reaffirmed that "the cost of debt is a cost of resource and, in the case of investor-owned utilities, the cost of debt is lowered by the contribution of equity by the company."[443]

3. <u>2026 ASCM Approach to ROE in ASC</u>

a. Replacing the IOUs' ROE with the Weighted Average Cost of Long-term Debt is Not Reasonable

Under the 2008 ASCM, BPA calculated over 60 ASCs for the IOUs and had found no instance where a utility or state commission had attempted to include terminated plant costs in ASC either directly or indirectly through the ROE. Thus, for the 2026 ASCM, BPA initially proposed no changes to the treatment of ROE in a utility's ASC. The increased focus on affordability at the state level further decreases the likelihood of state commissions artificially inflating the return on equity.

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their inclusion in ASC.")

435 *See* 2008 ASCM ROD at 103.

436 *Id.*

437 *PacifiCorp,* 795 F.2d 816.

438 *Id*. at 823.

439 2008 ASCM ROD at 104.

440 *Id.*

441 *Id*.

442 *Id.* at 107.

443 *Id.* at 104.

Public Power customers and AWEC oppose BPA's decision to include ROE in the 2026 ASCM and propose that BPA revise the treatment of a utility's return on equity and readopt the treatment employed in the 1984 ASCM. That treatment would remove the utility's return on equity and replace it with the "weighted average cost of long-term debt."[444]

BPA finds that removing ROE *entirely* from the 2026 ASCM and replacing it with the "weighted average cost of long-term debt" is not reasonable. The exclusion of ROE in the 1984 ASCM was a severe remedy to a specific problem. There, BPA proposed removing ROE to address the inclusion of costs that directly violated statutory prohibitions, specifically Section 5(c)(7)(C) costs. BPA never considered ROE, in itself, an invalid cost of a resource. In fact, ROE serves as a recognized method for financing capital improvements, such as new resources, through investors, offering an alternative to debt for for-profit utilities. Without equity investors, the utility's investments would "most likely be financed at higher rates."[445] BPA's decision in the 1984 ASCM to exclude state-approved ROE stemmed from its inability to confirm that a utility's ROE "was free of terminated plant costs."[446] However, the past decade of practice under the 2008 ASCM demonstrates that concerns regarding hidden terminated plant costs entering a utility's ASC through ROE are no longer relevant, making the inclusion of a utility's full ROE appropriate.

Public Power and AWEC, nonetheless, posit that BPA has a new ground for removing ROE. They contend that IOUs are compensated through the ROE for the risk associated with investing in a utility, which includes the risk of liability, like wildfire liability and disallowed costs.[447] These parties argue that if the utility's full ROE is included in ASC, REP payers "effectively bear both the risk premium embedded in authorized return on equity and the realized costs associated with that risk."[448] This, according to the Public Power customers, "would shift financial risk away from shareholders while allowing investors to retain compensation for bearing that risk."[449]

BPA disagrees that the ASCM is improperly including both a ROE and potentially disallowed costs from the FERC Form 1. Public Power customers and AWEC contend that there is a direct link between disallowed costs and a utility's ROE. However, BPA finds this connection to be less clear in practice. For example, while direct costs related to wildfire injuries and damages can have cascading effects—such as on the cost and availability of insurance, credit ratings, and the cost of capital—this does not mean the cost of injuries and damages is included in the ROE or that there is somehow double counting. These costs are additive; a utility would separately incur the cost of all of these cascading effects.

BPA also does not agree that replacing a utility's return on equity with the "weighted average cost of long-term debt" is a reasonable alternative.[450] As noted above, BPA

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[444] Public Power Comments (April) at 14; AWEC Comments (April) at 4.
[445] 1984 ASCM ROD at 53.
[446] *Id.* at 54.
[447] Public Power Comments (April) at 12-14.
[448] *Id.* at 14.
[449] *Id.*
[450] Public Power Comments (April) at 14.

adopted that approach in reaction to a certain utility's (and commission's) attempt to include statutorily prohibited costs (terminated generating plant costs) in a utility's ASC. That remedy was "severe" for its purpose,[451] and even the Court did not sanction its use indefinitely.[452] The corrective approach from the 1984 ASCM is not appropriate in this context, where the issue is not whether a cost is prohibited by the Northwest Power Act, but whether state regulators have properly balanced the interests of shareholders with ratepayers. ROE is a recognized cost of attracting capital for an *investor*-owned utility, and BPA does not agree that the Northwest Power Act requires it to ignore that "investment" aspect of a utility's structure to set its ASC.

b. The ROE Should Be Limited to Non-Transmission

However, Public Power and AWEC comments raise the issue that the cost of equity for financing assets will depend on the assets being financed and the risks associated with financing such assets. As discussed in *Issue 3.5.1*, Transmission costs should not be included as part of the average system cost of a utility's resources under Section 5(c) of the Northwest Power Act. Therefore, BPA will revise the ASCM to include a ROE tailored to the assets in the rate base of a utility's ASC. That is, the ASCM will utilize the ROE in FERC-approved transmission rates to remove the transmission-associated ROE from state commission-approved ROEs. BPA Staff presented this adjustment to the ASCM at the July 31, 2026, workshop, and requested stakeholder feedback.[453]

In their interim feedback on Staff's proposal, Public Power customers disagree with the inclusion of any ROE amount in the ASC, and assert removing transmission-associated ROE "would address a latent legal defect in the Draft 2026 ASCM."[454] Public Power customers also contend that "State commission and FERC precedent provide further support for BPA's proposal by recognizing that different utility functions can have different risk and capital characteristics."[455]

As BPA noted in the 1984 ASCM ROD, a return on equity attracts equity investments, which provides a prudent means of financing capital assets. Regulators approve returns sufficient to attract capital.[456] More specifically, it is axiomatic in utility regulation that a regulator aims to approximate the cost of equity for the financing of the assets for which the

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[451] 2008 ASCM ROD at 103.
[452] *PacifiCorp*, 795 F.2d at 823.
[453] ASCM Workshop 7, at 11-13, July 31, 2026.
[454] COU Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 3.
[455] *Id.*
[456] *See e.g., Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679, 692-93 ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property . . . equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . . ."). *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (return should be "commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.").

regulator is setting rates.[457] The task before a commission is to set an authorized ROE for the specific assets within its jurisdiction. Both state and federal commissions determine the ROE for assets in their respective jurisdictions. Here, since the NWPA does not include transmission assets in a utility's ASC for resources, it follows that the ASCM should only permit a cost of equity associated with generating and production-related assets in a utility's ASC.

A state commission-approved ROE is not the right data point for that task. The state commission is considering the assets under its jurisdiction, which is different from the assets included in a utility's ASC. Different assets carry different risk profiles and have different costs of equity. This type of distinction can be seen, for example, in *Public Service Commission of Kentucky v. FERC:*

> A major component of the rates charged by MISO is the return on equity (ROE) paid to its member utilities. This rate compensates the utilities for the capital cost of the grids they placed under MISO's control. FERC derives the rate by estimating the annual return an equity investor in the utility would expect on such capital, had the utility continued to operate the grid outside the RTO. *See generally Canadian Ass'n of Petroleum Producers v. FERC,* 254 F.3d 289, 293–94 (D.C.Cir.2001). Calculating this rate would be relatively easy if a utility's interest in its grid—its business as a transmission owner (TO)—were publicly traded, but 'there are no publicly traded independent pure electric transmission companies.' *MISO Initial Decision,* 99 FERC ¶ 63,011, 65,040, 2002 WL 32056864 (2002). The Commission must therefore resort to more roundabout estimations.[458]

A ROE is to compensate capital costs associated with, and equity investor expectations are tied to, specific assets. Further, FERC resorts to estimations when a utility's interest in specific assets does not have a ready proxy group. Here, the ASCM should have a ROE tied to the specific assets in the ASC. State commission-approved ROEs do not provide such a ROE. In the absence of a ROE determined for that precise purpose, BPA turns to the evidence at hand.

There are two compelling pieces of evidence readily available to determine a ROE tailored to the non-transmission assets in a utility's ASC. First, a ROE for a bundled utility product set by state commissions. Second, a ROE for unbundled transmission service set by FERC. Using this publicly available data, BPA can design the ASCM to approximate the regulator-defined risk premium associated with transmission assets relative to the exchanging utility's assets at large. Since the FERC ROE isolates the transmission component of ROE,

[457] *See, e.g., MISO Transmission Owners v. FERC,* 177 F.4th 1204, 1209-10 (D.C. Cir. 2026) (ROE "reflects the rate Transmission Owners receive as compensation for their investments *in MISO's transmission facilities*." Transmission rates "designed to recover costs and provide transmission owners a reasonable return on their investment *in transmission facilities.*") (emphasis added).

[458] *Pub. Serv. Comm'n of Kentucky v. FERC,* 397 F.3d 1004, 1006-07 (D.C. Cir. 2005).

the ASCM can mathematically solve for the non-transmission portion of the state ROE. This can be expressed in the formula discussed by BPA Staff at the July 31, 2026, workshop[459]:

$$Non\ Tran\ ROE = \frac{State\ ROE - (FERC\ Tran\ ROE * Tran\ Rate\ Base\%)}{Non\ Tran\ Rate\ Base\ \%}$$

$$\textit{Example:} \qquad 8.83\% = \frac{9\% - (9.60\% * 22\%)}{78\%}$$

Through the above formula, the ASCM weights the ROE to remove the return on equity associated with transmission, as determined in FERC-approved transmission rates. This allows a non-transmission ROE to be included in a utility's ASC. While current FERC transmission ROEs are often higher than state commission-approved ROEs, the ASCM approach does not require the non-transmission ROE to be lower than a state commission-approved ROE; the ASC ROE is simply calculated based on the approved ROEs of the relevant regulators.

In their interim feedback comments, the IOUs object that removing the transmission-related ROE is "fundamentally flawed" because it ignores that "a state ROE is determined for a company by its state commission based on its business as a whole. There is no such thing as separate ROEs for the various portions of a utility's business."[460] State commissions may not approve a ROE by summing ROEs separately calculated for various portions of a business. BPA's point is that the state commission-approved ROE is for the bundled product within its jurisdiction, which includes transmission. The assets required to provide this bundled product are different from those included in a utility's ASC. Therefore, an adjustment is appropriate to solve for a non-transmission ROE that reflects the assets in the ASC rate base.

The IOUs also object to using the FERC-approved transmission ROE as a proxy for a transmission-related portion of the state-approved ROE, given FERC's ROE is not a component of state-approved ROE, IOUs' bundled retail ratepayers do not pay FERC transmission rates, and FERC's ROE reflects FERC-specific policies.[461]

The IOUs' argument is beside the point. While state commissions and FERC may have different policy considerations, neither approach is required to be reflected in the ASCM. The NWPA does not dictate that the ASCM include a state-approved ROE as opposed to one derived from another source. If BPA develops a methodology to determine exchanging utilities' average system cost that includes a rate base and rate of return construct, BPA is not required to use state commission-approved ROEs as an input any more than BPA is required to use FERC Form No. 1 accounts as an input. The ASCM determines how to calculate a rate of return for ASC purposes. BPA's approach of utilizing the publicly available state commission and FERC ROEs to calculate a non-transmission ROE is

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459 ASCM Workshop 7, at 13, July 31, 2026.
460 IOU Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 3.
461 *Id.* at 3-4.

appropriate to the ASC rate base, and consistent with the considerations behind not returning to a jurisdictional approach to determining ASCs.

Alternatively, BPA could revise the methodology to include a process for BPA to independently determine an appropriate ROE for the rate base included in a utility's ASC. Such a process would likely require interested parties to provide expert testimony. As a matter of deference to other regulators, and to ease administrative burden, BPA prefers its approach here.

In conclusion, while Public Power and AWEC advocate for the removal of ROE from the ASCM, because of concerns that current practices lead to ratepayers bearing both risk premiums and realized costs, BPA finds that such an approach is unwarranted and impractical. Thus, BPA rejects a return to using the "weighted average cost of long-term debt," as this measure was used to address a specific situation (the inclusion of statutorily prohibited costs) and is not applicable to the current debate concerning state regulators' balancing of shareholder and ratepayer interests. Ultimately, BPA finds that the Northwest Power Act does not necessitate disregarding the investment aspect of a utility's structure when determining its ASC. At the same time, BPA finds that the state commission-approved ROE is not tailored to the cost of capital for the assets included in a utility's ASC. Instead, the ASCM will utilize publicly available ROEs approved by state commissions and FERC to calculate a non-transmission ROE to reflect the cost of capital for ASC assets.

Draft Decision

BPA will revise the 2026 ASCM to utilize the ROE in FERC-approved transmission rates to remove the transmission-associated ROE from state commission-approved ROEs. BPA will not revise the 2026 ASCM by removing a utility's return on equity and replacing it with the utility's "weighted average cost of long-term debt."

Issue 5.6.1.2

Whether BPA should remove federal income taxes from a utility's average system cost of resources.

BPA Staff's Proposal

Federal income taxes are a cost included in the 2026 ASCM.[462] Corporate federal income taxes are also used to gross up the utility's ROE in the weighted cost of capital.[463]

Parties' Positions

The Public Power customers argue that income taxes paid for by an IOU are "not a resource cost."[464] They contend that BPA "erroneously" concluded to include income taxes in the 2008 ASCM.[465] They further argue that excluding income taxes better "aligns" with the requirements of Section 5(c)(1).[466] Public Power customers urge BPA to adopt its rationale

[462] *See* Table 1, Schedule 3A: Taxes.
[463] *See* 2026 ASCM § 301.4(o)(1)-(2).
[464] Public Power Comments (April) at 14.
[465] *Id.*
[466] *Id.*

from the 1984 ASCM, which excluded federal income taxes because they were not a "resource cost" nor costs that should be equalized between Public Power and IOUs.[467] The 1984 ASCM characterized the inclusion of federal income taxes as "confer[ring] on investor-owned utilities the tax advantage of publicly owned utilities."[468] BPA, in the 1984 ASCM, concluded that the exchange should not be a "vehicle for redistributing tax burdens from exchanging utilities to BPA's other customers . . . ."[469]

In the alternative, Public Power customers argue that if BPA retains income taxes in a utility's ASC, BPA should revise the way they are treated under the ASCM.[470] Specifically, to align with IOU regulators, they suggest BPA adjust the IOUs' marginal income tax "gross-up." The Public Power customers note that the way the ASCM handles income tax expense is different from how income taxes are addressed in retail rates, which use straight-line depreciation.[471] This difference, according to the Public Power customers, results from the accelerated depreciation allowed by the IRS, which creates Accumulated Deferred Income Tax (ADIT).[472] They contend that IOU tax normalization requires regulators to set retail rates with a higher marginal income tax "gross up" during heavy investment periods due to accelerated depreciation, with ADIT appearing as a liability that reduces the rate base.[473] Therefore, Public Power customers suggest BPA incorporate this into the ASC by reclassifying Accounts 281 and 282 from Distribution/Other to PTD, which in their view would align BPA's 2026 ASCM with standard regulatory treatment of ADIT, as it results from investment across the utility plant, including production facilities.[474]

Evaluation of Positions

Public Power customers argue that income taxes paid for by an IOU are "not a resource cost."[475] BPA disagrees. The ASCM has always included more costs than bare capital plant; it includes related O&M expenses and overhead A&G. The chair in which a plant technician sits in is not itself a "resource" under the NWPA, but it is a cost of that resource. Similarly, the taxes associated with an electric utility financing and operating these resources as a for-profit entity are costs of resources. As BPA stated in the 2008 ASCM ROD, "[i]ncome taxes are a cost of resources in the same way as interest expense."[476]

As discussed in *Issue 5.6.1 (ROE),* BPA's 1984 decision to exclude federal income taxes and ROE was a severe remedy to a specific problem, which was challenged in the Ninth Circuit. The Ninth Circuit conditionally affirmed but did not "sanction any permanent implementation of these exclusions."[477] BPA believes the better position is the one stated

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467 *Id.*
468 *Id.* (*quoting* 1984 ASCM ROD).
469 *Id.*
470 *Id.* at 15.
471 *Id.*
472 *Id.*
473 *Id.*
474 *Id.*
475 *Id.* at 14.
476 2008 ASCM ROD at 115.
477 *PacifiCorp*, 795 F.2d at 823.

in the 2008 ASCM ROD, in which BPA found income taxes are a cost of resources. As the Oregon PUC then stated, "Federal income taxes are a normal, indeed unavoidable expense an investor-owned Utility incurs when acquiring resources and other capital needs."[478]

Public Power customers contend, citing the 1984 ASCM ROD, that the REP should not be a "vehicle for redistributing tax burdens from exchanging utilities to BPA's other customers . . . ."[479] However, the REP was enacted in response to a wholesale cost disparity between BPA and IOUs. BPA's operation at cost and the IOUs' operation for profit may contribute to the cost disparity between a utility's ASC and the PF Exchange rate. The rate of return and federal income tax burden are costs that IOUs incur.

Public Power customers argue that if BPA includes federal income taxes, BPA should "align its marginal income tax 'gross-up' with the tax normalization used by IOU regulators."[480] BPA disagrees. It is appropriate to gross up the ROE to reflect corporate federal income taxes. This recognizes that additional revenues will increase taxable income, thereby increasing the income tax to be paid. If this gross-up did not occur, the utility would be unable to earn its allowed return. Excluding income tax from an IOU's ASC would not reflect the financing costs of such a utility. It would exchange the cost of a hypothetical, imagined non-profit entity that had financed its capital program in a completely different way. As the 2008 ASCM ROD noted, since IOUs existed well before the NWPA, it was not as though IOUs chose to establish themselves as IOUs rather than a public power entity in order to take advantage of the REP.[481] Financing their capital programs and the related federal income tax burdens are simply costs they incur. Including federal income tax accurately represents their cost of financing and retaining investor capital in the resources necessary to serve their loads. BPA declines to pretend that IOUs are actually non-profit entities with different tax burdens than they actually have.

Public Power customers state their proposal "can and should be incorporated into the ASC by changing the functionalization codes for Accounts 281...and 282...from Distribution/Other to PTD."[482] Accounts 281 and 282 are deferred credit accounts, specifically "Accumulated deferred income taxes--Accelerated amortization property" (281) and "Accumulated deferred income taxes--Other property" (282). These ADIT accounts include tax deferrals resulting from the bookkeeping differences between taxable income and pretax accounting income caused primarily by the treatment of property for tax reporting. Utilities must receive state commission approval to transfer balances in these ADIT accounts.

> Account 281 – Accumulated deferred income taxes – accelerated amortization property is used to record tax deferrals of property with an accelerated depreciation schedule.

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[478] 2008 ASCM ROD at 115.
[479] Public Power Comments (April) at 15.
[480] *Id.*
[481] 2008 ASCM ROD at 115.
[482] Public Power Comments (April) at 15.

Account 282 – Accumulated deferred income taxes – other property is used to track tax deferrals of all other property that's not included in Account 281.

For ASC purposes, the ADIT accounts do not impact the ASC as each is functionalized to Distribution/Other except for the "modified net income" used to initially calculate the Account 925 5% threshold. If ADIT were brought into the rate base, the corresponding Accumulated Deferred Income Taxes, Account 190, would need to be brought in, as well as the federal income and other taxes found on Schedule 3A. This approach would run counter to the tax gross-up method historically employed and currently proposed (Schedule 2 of Appendix 1). As the rate of return gross up adds the additional cost of Federal tax assumed in the base year, its removal would be necessitated by the commensurate inclusion of all of the tax accounts mentioned above, including but not limited to ADIT.

Converting from BPA's simple gross-up methodology to Public Power's tax normalization proposal would not be as simple as they suggest. As BPA stated in the 2008 ASCM ROD:

> [d]etermination of the 'fair, just and reasonable' amount of income taxes to include in electric Utility revenue requirement has been the subject of what can easily [be] described as one of the most complex, contentious and longest running issues facing state commissions and FERC, stretching back to the 1950s when Congress passed the Internal Revenue Code of 1954, which permitted use of accelerated depreciation for income tax purposes.[483]

Indeed, in the 2008 ASCM ROD, while WPAG argued for including "actual taxes paid as included in the FERC Form 1," PPC and NRU recognized that including income tax "will greatly complicate the ASC review process because it will invite BPA to become involved in the various methods by which IOUs defer and/or avoid payment of income taxes, and to make judgments about the appropriateness of such decisions."[484] Introducing tax normalization into the ASCM would introduce a similar level of complexity. Tax normalization in IOU Transmission Formula Rates impacts multiple FERC accounts and contains numerous footnotes detailing the appropriate treatment. For example, NorthWestern's transmission formula rate includes "Note C"[485] for Accounts 190, 281, 282,

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[483] 2008 ASCM ROD at 116.
[484] 2008 ASCM ROD at 115-16.
[485] "The balances in Accounts 190, 281, 282 and 283 are allocated to transmission based on accounting records. Amounts associated with tax-related regulatory assets or liabilities, and financial instruments do not affect rate base. The balances in Accounts 190, 281, 282 and 283 as well as portions of the balances in Accounts 182.3 and 254 related to unamortized excess/deficient ADIT are also adjusted in accordance with Treasury regulation Section 1.167(l)-1(h)(6) and averaged in accordance with IRC Section 168(i)(9)(B) in the calculations of rate base in the projected revenue requirement and in the true-up adjustments. To the extent that ADIT activity in the projected revenue requirement or true-up adjustments is not required to be prorated in accordance with Treasury regulation Section 1.167(l)-1(h)(6), remaining ADIT activity will be averaged using the beginning-of-year and end-of-year amounts or by multiplying the monthly activity by 50 percent. The balances in Accounts 182.3 and 254 related to unamortized excess/deficient ADIT and affecting rate base are reflected prior to gross-up to the revenue requirement level. Estimated annual ADIT activity is analyzed in Table 11, Workpaper B-2_Proj, and actual ADIT activity is analyzed in Table 12, Workpaper B-2_Act.

and 283; "Note P"[486] for Accounts 182.3 and 254; "Note Q"[487] for Tax Effect of Permanent Differences and AFUDC Equity (grossed-up); and "Note O"[488] for Investment Tax Credit Amortization.[489] Some of this data is derived, not from FERC Form 1, but from Company Records.[490] These accounts are functionalized, not by a functionalization ratio, but by direct analysis.[491] These aspects, if incorporated into the ASCM, would dramatically increase the workload and contentiousness of the ASC review process.

Further complexity is added by changes to tax rates, as was seen when the Tax Cuts and Jobs Act of 2017 (TCJA) reduced federal income taxes. This change required adjustments to balances for accrued income taxes and ADIT, and a flowback of excess deferred income taxes through rate reductions over a period no longer than the remaining economic life of the assets that generated the deferred tax reserves. Such issues were often contested and complex.[492] It continues to be true that "BPA staff does not possess the expertise to prepare an independent analysis of electric Utility income tax, nor does it think that it should obtain such expertise for ASCM purposes."[493] The proposed ASCM has flexibility to adjust to existing tax rates without deferring and returning excess deferred income tax. BPA declines to enter this morass, especially where a reasonable alternative is readily available.

Estimated annual activity for balances in Accounts 182.3 and 254 related to unamortized excess/deficient ADIT is analyzed in Table 13, Workpaper B-3_Proj and actual unamortized excess/deficient ADIT activity is analyzed in Table 14, Workpaper B-3_Act. Averaging and proration of ADIT balances and unamortized excess/deficient ADIT balances are computed in Table 15, Workpaper ADIT Averaging_Proj, and averaging and proration of ADIT balances and unamortized excess/deficient ADIT balances are computed in Table 16, Workpaper ADIT Averaging_Act." NorthWestern Corporation (Montana) OATT, Att. O (Transmission Formula Rate Template), tbl. 6, n.C, *available at* https://www.oasis.oati.com/NWMT/index.html.

486 "Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense (lines 118-119) by the amount of the excess or deficiency multiplied by (1/(1-T)) (lines 124-125)." *Id.* n.P.

487 "Includes the annual income tax cost or benefits due to permanent differences between the amounts of expenses or revenues recognized for ratemaking purposes and the amounts recognized for income tax purposes. Also includes the cost of income taxes on the depreciation of Allowance for Other Funds Used During Construction. The tax expense or benefit (line 120) related to these items increases or reduces the revenue requirement by the amount of tax expense or benefit multiplied by (1/(1-T)) (line 126)." *Id.* n.Q.

488 "NorthWestern has elected to amortize investment tax credits against recoverable income tax expense, rather than to reduce rate base by unamortized investment tax credit. Amortization reduces income tax expense and reduces the revenue requirement by the amount of the Investment Tax Credit Amortization (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 30)." *Id.* n.O.

489 *Id.*, Attachment O, tbl. 6.

490 *See id.*

491 *See id.*

492 *See generally Pub. Util. Transmission Rate Changes to Address Accumulated Deferred Income Taxes,* Order No. 864, 169 FERC ¶ 61,139 (2019), *order on reh'g & clarification*, Order No. 854-A, 171 FERC ¶ 61,033 (2020).

493 2008 ASCM ROD at 117.

Draft Decision

BPA will not remove federal income taxes from a utility's average system cost of resources.

5.7 New Large Single Load treatment (CFR § 301.4(p))

Section 5(c)(7)(A) of the NWPA prescribes the exclusion from ASCs "…the cost of additional resources in an amount sufficient to serve any new large single load of the utility." The ASCM revised its methodology to ensure additional costs to serve NLSLs are always removed from ASCs.

An NLSL is a load that grows by 10 average megawatts or more over a consecutive 12-month period, at which point the NLSL is triggered. Utilities are required to report active NLSLs on Schedule 4 of their Appendix 1s. Such utilities will populate the NLSL information, where applicable, on the NLSL tab of their Appendix 1 template. The timing of when a utility triggers an NLSL determines the method used to calculate applicable resource costs.

The costs to be removed from a utility's ASC will be based on its Base Period ASC for legacy or pre-2026 NLSLs. The total Contract System Load is reduced by the NLSL(s) and the total Contract System Cost is reduced by the NLSL(s) multiplied by the Base Period ASC.

Under the 2008 ASCM, in instances where the cost to serve a utility's NLSL fell below its Base Period ASC, NLSLs and applicable resource costs were retained in ASC. This occurred because under the 2008 ASCM, the NLSL calculation used only a subset of costs that at times produced an NLSL ASC below the utility's Base Period ASC. In such instances, if the NLSL and commensurate resource costs were removed, the utility's ASC would increase. BPA removed that limitation in the 2026 ASCM, concluding that such an outcome was not required by the Act.

5.7.1 Issues

Issue 5.7.1.1
Whether BPA should modify its proposal for calculating the resource costs sufficient to serve a new large single load.

BPA Staff's Proposal

Section 301.4(p) of the 2026 ASCM sets forth the rules for excluding costs sufficient to serve a utility's new large single load. The 2026 ASCM identifies two calculations for removing these costs, depending on when the NLSL comes into effect and whether the 2026 ASCM is in effect. For legacy NLSLs – those that were online prior to the effective date of the 2026 ASCM – the amount of costs removed is based on the utility's Base Period ASC.[494] For new NLSLs – those after the effective date of the 2026 ASCM – the cost of resources removed will be "on the average costs of post-2026 resources and long-term (LF)

[494] 2026 ASCM § 301.4(p)(2).

power purchases (five-year duration or longer), and then at the Utility's Base Period ASC for any remaining NLSL load."[495]

Parties' Positions

Public Power customers support BPA's updated NLSL methodology, which simplifies implementation, removes informal resource dedication, and mitigates opportunistic behavior.[496] They note that this revised framework ensures consistent treatment of existing interests while clearly enabling the removal of the NLSL exception.[497] Furthermore, Public Power customers endorse BPA's proposal to allocate new resource costs to new NLSLs, aligning with cost-causation principles and BPA's statutory responsibilities.[498]

AWEC states that the 2026 ASCM's approach is "directionally consistent" with what AWEC views as the appropriate removal of resource costs associated with serving a utility's NLSL.[499] However, AWEC contends that changes in the utility industry may result in greater specificity regarding service to an NLSL going forward. As such, AWEC suggests adding language to § 301.4(p) to remove costs for resources procured specifically for an NLSL after the 2026 ASCM effective date.[500] Additionally, AWEC recommends adding the word "weighted" to ensure the average reflects the actual relative size and cost of each resource.[501]

Evaluation of Positions

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[.]"[502] Section 301.4(p) of the 2026 ASCM sets forth the rules for excluding costs sufficient to serve a utility's new large single load. As noted above, it identifies two methods for calculating such exclusions, one of which addresses existing NLSLs, and another which will apply to NLSLs that occur after the effective date of the 2026 ASCM.

Public Power customers support § 301.4(p) of the 2026 ASCM as drafted.[503]

AWEC contends that the 2026 ASCM's approach is "directionally consistent" with what AWEC views,[504] but suggests adding language to § 301.4(p) to remove costs for resources procured specifically for an NLSL after the 2026 ASCM effective date.[505] Additionally,

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495 *Id.* § 301.4(p)(1).
496 Public Power Comments (April) at 9.
497 *Id.*
498 *Id.*
499 AWEC Comments (April) at 4.
500 *Id.* at 5.
501 *Id.*
502 16 U.S.C. § 839c(c)(7)(A).
503 Public Power Comments (April) at 9
504 AWEC Comments (April) at 4.
505 *Id.* at 5-6.

AWEC recommends adding the word "weighted" to ensure the average reflects the actual relative size and cost of each resource.[506]

BPA appreciates AWEC's thorough and thoughtful comments and agrees that its proposed changes have improved upon the draft submitted by BPA Staff. Therefore, with one minor clarification, BPA intends to adopt them. Specifically, BPA intends to adopt the following changes (**bolded below**) to § 301.4(p):

> (p) Treatment of New Large Single Load (NLSL). Bonneville will remove from the Utility's ASC any NLSL and the cost of additional resources sufficient to serve any NLSL that was not contracted for, or committed to, prior to September 1, 1979. The commensurate resource costs to be removed will be determined as follows:
>
> (1) For a Utility with NLSLs that become operational after the effective date of this 2026 ASCM, the resource costs **for NLSLs without contractually-dedicated resources procured by the Utility to serve those NLSLs** will be based first on the **weighted** average costs of **all non-dedicated** post-2026 resources and long-term (LF) power purchases (five-year duration or longer), and then at the Utility's Base Period ASC for any remaining NLSL load.
>
> > (i) For purposes of determining the average costs of the Utility's post-2026 resources, Bonneville will include an individual resource's fixed and annual costs, and a portion of general plant, A&G, other expenses and revenues, and LF power purchases. The resource costs will exclude (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to Section 5(c) of the Northwest Power Act; and (c) resources sold to Bonneville, pursuant to Section 6(c)(1) of the Northwest Power Act.
>
> **(2) For a Utility with NLSLs that become operational after the effective date of this 2026 ASCM, the resource costs for NLSLs with contractually-dedicated resources procured by the Utility to serve that NLSL load will be based first on the costs of those post-2026 resources and LF power purchases (five-year duration or longer). Any remaining NLSL load after the contractually dedicated resources will be determined in accordance with section 301.4(p)(1).**

As AWEC notes, state laws regarding the treatment of large loads are evolving, and new methods for calculating a utility's resources are emerging as states implement more stringent measures to allocate resource costs to specific loads.[507] While many of these laws

[506] *Id.*
[507] AWEC Comments (April) at 4-5.

are still in their infancy—and it remains to be seen whether utilities will actually purchase specific resources to serve specific NLSLs—BPA agrees that when utilities earmark specific purchases for NLSLs, the costs of those resources should be excluded from the utility's ASC. This approach aligns with both the letter and the intent of Congress's directive that BPA exclude the cost of "additional resources in an amount sufficient to serve any new large single load of the utility." [508]

The one modification BPA made to AWEC's language was to remove the reference to "actual" resource costs. BPA believes that requiring "actual" costs unnecessarily limits the calculation to historical data, especially when estimates of future purchases are readily available.

Draft Decision

BPA will adopt AWEC's proposed revisions to § 301.4(p) with minor changes as described herein.

5.8 Special Instructions for Certain FERC Accounts (CFR § 301.4(q)-(y))

5.8.1 Overview

Beyond functionalization codes for specific FERC accounts, the ASCM outlines specialized instructions for particular accounts. These additional instructions are detailed in § 301.4(q)-(y). Previously, many of these instructions were found in the endnotes of the ASCM. BPA has since integrated them into the regulation's main body to enhance usability and emphasize their substantive role within the ASCM.

5.8.2 Conservation Costs (CFR § 301.4(q), (s), (t))

Conservation and conservation-related costs are a cost of a utility's resources, and are generally functionalized to Production. Nonetheless, a utility's conservation costs may appear in any number of FERC accounts. Thus, the ASCM contains specific provisions addressing how a utility may identify and functionalize conservation costs. Revenues arising from the sales of renewable energy credits (RECs) are functionalized to Production and are netted against the utility's Contract System Cost. In the 2008 ASCM, Customer Assistance Expense (Account 908) was highlighted by IOUs as an account that holds conservation-related and demand side-management (DSM) costs. Conservation costs reported in Account 908 may be functionalized through a Direct Analysis. Demand-side management and demand response (DR) costs are not considered conservation.

The ASCM also contains specialized rules for Oregon utilities that pay into the Public Purpose Charge for conservation-related measures such as renewable resource development, acquisition, and implementation.

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[508] 16 U.S.C. § 839c(c)(7)(A).

5.8.3 Cash Working Capital (CFR § 301.4(r))

Cash Working Capital (CWC) is a component of rate base. Schedule 1A determines the allowable amount of CWC to be included in ASC, which consists of total production expenses, A&G, less purchased power, fuel, and any Public Purpose Charges.

5.8.4 Production Revenues (CFR § 301.4(u))

Production-related revenues are functionalized to Production or as assigned via Direct Analysis, and are netted against the utility's Production costs. Only net Production costs are used to determine a utility's ASC. Such costs are reported on Schedule 3B. The sum of Schedule 3B nets against the sum of the utility's rate base and expenses.

5.8.5 Energy Storage Costs (CFR § 301.4(v))

The 2026 ASCM includes a new provision for energy storage projects, such as batteries. BPA acknowledges that energy storage projects can support multiple operations, including Production, Transmission, and Distribution functions. Previously, FERC separated energy storage projects into multiple accounts based on their function. However, in FERC Order No. 898, the Commission combined these into a single account. Consequently, for the 2026 ASCM, BPA revised its approach to energy storage projects. Utilities now have two options for functionalizing these costs in their Appendix 1: Direct Analysis or applying a PTD ratio. This functionalization method applies to the entire account, not to individual resources. Therefore, any change in functionalization affects the entire account. If utilities choose Direct Analysis, they must provide sufficient documentation demonstrating that the energy storage resources are production-related.

5.8.5.1 Issues

<u>Issue 5.8.5.1.1</u>
Whether BPA's proposed methodology for functionalizing Energy Storage Plant is reasonable.

<u>BPA Staff's Proposal</u>

Under § 301.4(v) of the 2026 ASCM, "Bonneville will allow DIRECT functionalization of Energy Storage Plant or PTD as default ratio. Energy Storage Expenses: Operation, and Energy Storage Expenses: Maintenance costs will apply the same functionalization as Energy Storage Plant."

At the December 3, 2025 workshop, BPA explained its proposal to consolidate Energy Storage Plant costs to reflect FERC Order No. 898, and that this consolidation raised the issue of how the ASCM would functionalize such costs.[509] BPA explained that functionalization was not clear cut—batteries can serve multiple uses;[510] FERC has recognized that batteries can be transmission-only assets; batteries may appear

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[509] ASCM Workshop 2, Dec. 3, 2025, at 22.
[510] *Id.* at 23 (listing arbitrage, firm capacity, ancillary services, deferring distribution investments, reduce end-use consumer demand charges, peak shaving, operating reserves, deferring transmission investments, advanced microgrid setup, and black start).

uneconomical compared to other production technologies but be justified by a combination of values; a utility may change its use of a battery over time; and regulatory bodies may apply a case-by-case analysis of use and cost-causation.[511] Therefore, "[g]iven the dynamic nature of the technology and industry, BPA Staff were concerned attempts at a more precise functionalization methodology would not age well," leading Staff to propose functionalizing Energy Storage Plant accounts using the PTD ratio.[512]

In response to comments concerned with the lack of flexibility in the PTD ratio,[513] BPA Staff proposed to allow the option to functionalize costs by direct analysis supported by documentation, or to default to the PTD ratio.[514]

Staff later clarified:

> During the workshop, stakeholders noted that the use of a battery may change over time, and questioned whether the functionalization of a battery in one Base Period would carry over to another. BPA understands that a battery's utility may change over time and allowing a utility to choose either the PTD ratio or DIRECT in each Base Period attempts to capture evolving usage of these resources.[515]

<u>Parties' Positions</u>

WUTC supports BPA's proposal.[516] WUTC reasons, "[a]s battery energy storage systems can be used in a variety of ways, utilities must be able to allocate costs depending on how they use the battery resource. Allowing utilities to determine the best functionalization method dependent on their unique needs provides all parties with the flexibility to adapt and evolve as battery technology advances."[517]

Public Power customers oppose BPA's proposal.[518] Public Power customers argue that the option between PTD and DIRECT functionalization creates "structural asymmetry" and is inconsistent with the principle of preventing inappropriate or excessive costs from entering the ASC.[519] Public Power customers propose BPA instead use a fixed PTD ratio that is the same for all utilities.[520] Alternatively, Public Power customers propose BPA require direct analysis, with a default to DIST/OTHER.[521]

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511 *Id.*
512 *Id.* at 24.
513 ASCM Workshop 4, Jan. 27, 2026, at 12.
514 *See* ASCM Workshop 5, Feb. 13, 2026, at 9.
515 BPA Staff Clarification to Draft 2026 ASCM, Feb. 20, 2026, at 3-4.
516 WUTC Comments (April) at 3.
517 *Id.*
518 Public Power Comments (April) at 8-9.
519 *Id.* at 8.
520 *Id.*
521 *Id.* at 8-9.

AWEC argues that BPA's proposal "may not best support principled functionalization."[522] AWEC proposes that the ASCM should require utilities to provide "commission orders approving ratemaking treatment, including how such Energy Storage Device costs are functionalized for retail ratemaking purposes and contemporaneous documentation of how these assets have actually operated over the Base Period."[523]

Evaluation of Positions

As noted above, the 2026 ASCM is adding a new provision that applies specifically to energy storage projects, *e.g.,* batteries and the like. The proposed approach to these projects is to allow utilities to use either a DIRECT functionalization (where the utility supports its proposed functionalization with documentation) or the default ratio of PTD.

Functionalization ratios are appropriate where, as here, there is not a simple, objective, agreed-upon method to specifically calculate which costs within an account are specifically attributable to different functions, or where direct assignment of costs to functions is otherwise impractical. Functionalization ratios are, by nature, a form of rough justice. As Staff discussed, functionalization of energy storage is not clear cut.[524] WUTC agrees that "battery energy storage systems can be used in a variety of ways" and supports the ASCM "provid[ing] all parties with the flexibility to adapt and evolve as battery technology advances."[525] It may not be clear which function caused the cost of a battery to be incurred, or which function receives the benefit. This complexity could arise from different batteries being used for different purposes, and from individual batteries being used for multiple purposes. Further, a battery may initially be purchased based on a certain combination of values from certain expected uses, and then used by different functions over time. Even with a full direct analysis, there may not be a clear, objective "right" answer. For example, AWEC asserts, "[i]t may be that, regardless of functionalization for purposes of setting retail rates, actual operations dictate a different outcome for purposes of calculating a utility's ASC."[526] This would pit AWEC's opinion against that of a state commission.

Energy Storage Plant, like several other costs in the ASCM, allows for two functionalization methods. If the functionalization is clear cut—such as a single battery recognized by FERC as a "Storage as a Transmission-Only Asset" or "SATOA"—the utility may use direct analysis. If not, the utility may use the PTD ratio. While Public Power and AWEC are concerned with participating utilities cherry-picking the higher method, or having functionalizations applied that do not reflect reality, the ASCM contains provisions that mitigate these risks.

For instance, the 2026 ASCM mitigates this risk by requiring a utility to stick with the methodology it chooses unless it receives express BPA approval to change. Under § 301.4(l), "[o]nce a Utility uses a specific functionalization method for an Account, the

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522 AWEC Comments (April) at 6.
523 *Id.*
524 ASCM Workshop 2, Dec. 3, 2025, at 23.
525 WUTC Comments (April) at 3.
526 AWEC Comments (April) at 6.

Utility may not change the functionalization method for that Account without prior approval from Bonneville." Further, even if the utility uses the PTD ratio, BPA still has the ability to ensure that the utility is properly accounting for its costs within the applicable FERC Accounts. Under section 3.2.2 of the ASC Procedures, "[i]n calculating ASCs, BPA will make an independent determination of (1) the appropriateness of the inclusion of costs; (2) the reasonableness of the costs included in Contract System Costs; and (3) the appropriateness of Contract System Loads." Parties may also file data requests under section 3.3 of the ASC Procedures. While BPA's proposed methodology is flexible, that flexibility exists within procedural constraints.

Public Power customers propose two alternatives. The first would apply "a fixed Production-Transmission-Distribution (PTD) allocation ratio, applied uniformly across all participating utilities . . . ."[527] Public Power proposes a different PTD ratio than is used in other areas of the ASCM, where the PTD ratio is based on each utility's relative Production, Transmission, and Distribution plant. Here, Public Power proposes "BPA should specify the PTD ratio in the 2026 ASCM, drawing on available functional cost data from existing utility filings, so that the allocation is transparent, predictable, and not subject to manipulation through selective application of DIRECT analysis."[528] BPA disagrees that a fixed PTD ratio established in 2026 should apply to a dynamic and growing sector of the industry. Indeed, such an approach would be patently unreasonable as there would be no basis to apply the same ratio to different utilities with potentially wildly different relative plant. Moreover, it is far from clear that an analysis of "available functional cost data from existing utility filings" would result in an objective ratio that all would agree with. Even if such a ratio could be calculated using current data, it is almost certain that such an analysis would become stale in the near future. BPA declines to adopt this proposal.

Public Power's second proposal is to "modify the optional functionalization to Distribution/Other (DIST) rather than PTD" because "[t]his would eliminate the structural bias created by the current proposal, while still allowing utilities to demonstrate the appropriate functional use of storage resources through Direct Analysis."[529] As discussed above, it is likely that the functionalization of this account will not be clear cut. BPA believes it would be inappropriate to penalize utilities by excluding potential Production-related costs from ASC because of an inability to perform a direct analysis. This proposal puts a lot of pressure on an assumption that direct analysis will yield a clear result. Instead, BPA believes the appropriate balance is to allow flexibility between PTD and direct analysis, hemmed in by the procedural structure discussed above.

Draft Decision

BPA's methodology for functionalizing Energy Storage Plant is reasonable.

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[527] Public Power Comments (April) at 8.
[528] *Id.*
[529] *Id.* at 8-9.

5.8.6 Regulatory Assets and Liabilities (CFR § 301.4(z))

Under the 2008 ASCM, utilities were required to perform a direct analysis on regulatory assets to ensure "regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC."[530] Additionally, in the 2008 ASCM ROD, BPA explicitly stated that regulatory assets and liabilities would not be included in an ASC at a level exceeding state commission approvals: "Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates."[531]

Although this substantive requirement has been enforced in every ASC since 2008, it was never explicitly written into the text of the ASCM itself. BPA added language to § 301.4(z) to formally codify this rule from the 2008 ASCM ROD. BPA discussed this addition at its July 31, 2026 workshop.[532]

5.8.7 Injuries and Damages – Account 925 (CFR § 301.4(w))

FERC Account 925 records utility costs and insurance payouts related to injuries and damages, offset by reimbursements. FERC Account 925 is an overhead "Administrative & General" operating expense account for "Injuries and damages." FERC's System of Accounts sorts Operation and Maintenance (O&M) Expense into various categories. There are O&M expense accounts under categories including, *e.g.*, "Power Production Expenses," "Transmission Expenses," "Distribution Expenses," and "Administrative and General Expenses" (A&G). Account 925 is included as an Operation Expense in FERC's System of Accounts under "Administrative and General Expenses."[533] Other A&G Operation Expense accounts include, *e.g.*, Administrative and general salaries (Account 920) and Office supplies and expenses (Account 921).

The 2008 ASCM treated Account 925 as a direct input into a utility's ASC using a Labor ratio.[534] This approach for Account 925 was reasonable under the 2008 ASCM because, historically, this account was a small portion of a utility's ASC, averaging around 0.25% of a utility's production costs since 2006.[535] That changed in 2023 when one exchanging utility recorded approximately $1.7 billion in Account 925, resulting in an ASC expense exceeding

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530 2008 ASCM at 149.
531 *Id.*
532 *See* ASCM Workshop 7, at 16, July 31, 2026.
533 18 C.F.R. Part 101, "Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act," *available at* *https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101*.
534 The Labor ratio functionalizes the costs in an account based on the utility's division of employee costs. Thus, for instance, if 60 percent of employees' salaries were allocated to Production, 25 percent to Transmission, and 15 percent to Distribution, the LABOR ratio would functionalize costs in the applicable account in this same manner.
535 *See* Historical Percentages of Account 925 Since 2006, Feb. 20, 2026, available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/202602-20-ascm-925-of-total-production-costs.xlsx.

$700 million, largely due to wildfire liability.[536] This single account increased that utility's Production costs by over 12 percent.[537] Furthermore, because costs reported in Account 925 do not necessarily align with costs approved by state regulators, the utility was not required to demonstrate that these costs were actually recovered from regional ratepayers, as opposed to being assigned by state regulators to company investors or set aside for future rate recovery. Given the potential for other utilities to face significant liability in Account 925, BPA decided to review how "injuries and damages" costs were included in a utility's ASC, and to implement additional documentation requirements for Account 925. Consequently, BPA proposed to include additional documentation requirements for Account 925 in the 2026 ASCM to address potential future liabilities.

5.8.7.1 Issues

<u>Issue 5.8.7.1.1</u>

Whether BPA's methodology for functionalizing injuries and damages costs (including FERC Account 925) is reasonable and consistent with statute.

<u>BPA Staff's Proposal</u>

In the Draft 2026 ASCM, BPA Staff proposed a two-step process to determine the amount of Account 925 costs to be included in a utility's ASC:

- **Step 1 (The 1% Threshold):** A utility can automatically include all Account 925 costs if they are equal to or less than 1% of the utility's total Production costs. No additional documentation is required. These costs will be functionalized by the LABOR ratio.
- **Step 2 (Exceeding the Threshold):** If Account 925 costs exceed the 1% threshold, the utility may provide state utility commission orders demonstrating the amount of Account 925 costs approved to be recovered in retail rates. Importantly, the utility must also demonstrate that such costs have not been recovered—in any Base Period—through other accounts (e.g. Account 925, or Regulatory Assets or Liabilities). The amount included in "State approved Injuries and Damages" would exclude costs recovered through other accounts to ensure there is no double recovery. The costs included in line item "State approved Injuries and Damages," may be functionalized either by a Direct Analysis or the LABOR ratio. If the utility chooses to *not* provide state utility commission orders, then the utility may only include in ASC costs from Account 925 up to 1% of its Production costs.[538]

BPA Staff clarified this provision:

> The intent is for "normal" Account 925 costs to automatically flow into ASC via the LABOR ratio, and avoid the complexity of a jurisdictional approach where specific items may not regularly be called out in commission orders. However,

[536] *Id.*

[537] *Id.*; *see also* Historical Percentages of Account 925 Since 2006, Feb. 20, 2026 (line 64, showing PacifiCorp 925 of $727 million).

[538] 2026 ASCM, § 301.4(w).

> very large and statistically uncommon damages should require a closer look. This reflects the scrutiny of such costs by state commissions in choosing whether and how to allow retail rate recovery. Account 925 costs functionalized to PROD that exceed 1% of the Utility's total system cost are still eligible to be included in the Utility's current or future ASC, but require documentation that such costs were allowed to be recovered in retail rates in the Base Period, e.g., as a regulatory asset or State approved Injuries and Damages. For purposes of calculating the 1%, the Utility's total system cost includes the full Account 925 amount.[539]

Parties' Positions

The IOUs and WUTC argue that BPA's proposal impermissibly *limits* costs in a utility's ASC.[540] Public Power customers disagree.[541]

Public Power customers argue that BPA's proposal impermissibly *includes* costs in a utility's ASC.[542] The IOUs and the WUTC disagree.[543]

Public Power customers and AWEC also argue that BPA's methodology should exclude certain injuries and damages costs resulting from wildfires.[544]

The IOUs and WUTC argue that BPA's proposal to require state approval under certain circumstances is unreasonable because of timing mismatches and regulatory lag.[545]

Commenters also disagree on the 1 percent threshold in the 2026 ASCM. The IOUs argue the initial 1% cap on including Account 925 costs is arbitrary, WUTC argues the initial cap is arbitrarily low, and AWEC argues the initial cap is arbitrarily high.[546]

The IOUs argue that all Account 925 costs should be allowed into a utility's ASC to achieve symmetry with BPA ratemaking.[547]

The IOUs also argue that all Account 925 costs should be allowed in ASC because Account 925 costs are included in some FERC-approved formula rates.[548]

Evaluation of Positions

Commenters raised several issues regarding BPA Staff's proposal to establish a 1% threshold for including Account 925 costs in a utility's ASC. Public Power customers and AWEC argue that the proposed threshold is arbitrarily high, whereas the WUTC contends it is arbitrarily low. Meanwhile, the IOUs argue that no threshold should be applied at all.

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539 BPA Staff Clarification to Draft 2026 ASCM, Feb. 13, 2026.
540 IOU Comments (April) at 11-12; WUTC Comments (April) at 4-5.
541 Public Power Comments (April) at 11.
542 *Id.* at 10-11.
543 IOU Comments (April) at 11-12; WUTC Comments (April) at 5.
544 Public Power Comments (April) at 11; AWEC Comments (April) at 7.
545 IOU Comments (April) at 12; WUTC Comments (April) at 5.
546 IOU Comments (April) at 12; WUTC Comments (April) at 4-5; AWEC Comments (April) at 6-7.
547 IOU Comments (April) at 12.
548 *Id.*

BPA intends to retain a threshold, above which additional documentation is required. However, in light of comments received, and upon further review, BPA has decided to revisit the threshold outlined in **Step 1** for its Account 925 proposal. As discussed below, BPA intends to revise the threshold to 5% of a utility's modified net income. Account 925 costs below that new threshold may automatically be included in a utility's ASC without additional documentation. Account 925 costs *above* that new threshold may also be included in ASC if supported by state commission orders (**Step 2**).

1. <u>BPA's Revisions to the 1% Threshold in Step 1 for Account 925: 5% of Utility Modified net Income</u>

The 1% threshold originally proposed by Staff was calculated based on the IOUs' historic inclusion of costs in Account 925 as compared to their total costs in ASC, going back to 2006.[549] BPA recognizes that—in basing the 1% threshold on historical actuals from exchanging utilities—Staff's data considered a fairly small sample size. Therefore, at the July 31, 2026 workshop, Staff discussed how it was researching whether there were other potentially analogous thresholds within the industry.[550] Staff noted that some commissions used a 5% of net income threshold, Oregon statutes included in ORS 757.259 a means of capping the amortization of deferred costs to a rate impact of 3%, and auditors assessing materiality using a variety of quantitative benchmarks.[551] Staff requested input on whether there are standard materiality thresholds in use at the state commission level, and how similar thresholds could apply to the inclusion of Account 925 costs in the ASCM.[552]

Stakeholders did not provide any viable alternatives, with the IOUs asserting no threshold was appropriate,[553] and Public Power renewing their request to require state-commission orders for all Account 925 costs and categorically exclude all wildfire-related costs.[554] The WUTC "question[ed] BPA's rationale to limit injury and damages to only 1%" but provided two citations "to provide a sense of similar thresholds applicable to Washington utilities."[555] BPA reviewed the WUTC's citations and concluded they did not provide criteria better than BPA's original 1%.

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549 The 1% threshold was calculated based on the IOUs' historic inclusion of costs in Account 925 as compared to their total costs in ASC, going back to 2006. *See* Historical Percentages of Account 925 Since 2006, Feb. 20, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/202602-20-ascm-925-of-total-production-costs.xlsx.
550 ASCM Workshop 7, July 31, 2026, at 15.
551 *Id.*
552 *Id.*
553 IOU Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 6-7.
554 COU Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 6.
555 WUTC Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 1-2 (citing RCW 80.28.425(6) (defer revenues in excess of 0.5% higher than authorized rate of return); and RCW 19.405.060(3)(a) (IOU complies with greenhouse gas neutrality if cost of compliance equals 2% increase in sales revenue)).

Nonetheless, after conducting additional research, BPA believes an appropriate threshold is available in the FERC System of Accounts, General Instruction 7, which addresses "Extraordinary Items."[556] It states:

> It is the intent that net income shall reflect all items of profit and loss during the period with the exception of prior period adjustments as described in paragraph 7.1 and long-term debt as described in paragraph 17 below. Those items related to the effects of events and transactions which have occurred during the current period and which are of unusual nature and infrequent occurrence shall be considered extraordinary items. Accordingly, they will be events and transactions of significant effect which are abnormal and significantly different from the ordinary and typical activities of the company, and which would not reasonably be expected to recur in the [foreseeable] future. (In determining significance, items should be considered individually and not in the aggregate. However, the effects of a series of related transactions arising from a single specific and identifiable event or plan of action should be considered in the aggregate. *To be considered as extraordinary under the above guidelines, an item should be more than approximately 5 percent of income, computed before extraordinary items.* Commission approval must be obtained to treat an item of less than 5 percent, as extraordinary. (See accounts 434 and 435.)[557]

In addition to its applicability to the FERC Form No. 1, which is the primary input to a utility's ASC, this threshold has been applied by state commissions as well.[558] The Montana PSC stated:

> In determining whether an amount is material, the Commission has found persuasive FERC's materiality standard suggesting an amount is extraordinary when, "more than approximately 5 percent of income, computed before extraordinary items."[559]

The comity of this threshold with FERC accounting and state commission practice is an advantage over Staff's data-driven-but-idiosyncratic 1% threshold.

The issue of "extraordinary items" arises when a utility experiences significant income or deductions that were not included in the test year for their rates. If a commission determines such income or deduction qualifies as an "extraordinary item," the amount can be preserved and possibly recovered in future rates.

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[556] 18 C.F.R. Part 100.
[557] *Id.*
[558] *See, e.g., In the Matter of the Application of Montana-Dakota Utilities Co. for Authority for Deferred Accounting Treatment,* Docket No. 2019.11.086, Order No. 7711a, 2020 WL 3440915, ¶ 21 (Montana PSC, 2020).
[559] *Id.* (citing Order 6829, ¶ 11; Order 7252, ¶¶ 6, 9; 18 C.F.R. pt. 101 (2017) (See FERC General Instructions, Section 7, Extraordinary Items)).

BPA views the FERC's and MPSC's test for "extraordinary items" as a reasonable proxy for the threshold in **Step 1** of BPA's proposal for Account 925. It is aimed at determining whether an amount is large and irregular, such that it could distort a utility's ASC. It is aimed at helping define when an amount is "extraordinary;" whether they are "related to the effects of events…of unusual nature and infrequent occurrence;" whether they are "abnormal and significantly different from the ordinary and typical activities of the company, and which would not reasonably be expected to recur in the [foreseeable] future."[560] A utility generally does not plan to experience recurring injuries and damages, and very large amounts should be carefully reviewed before concluding they are simply part of the regular cost of doing business.

The 5% threshold metric is also aimed at preventing ASCs from wildly diverging from the Account 925 costs state commissions are allowing to be recovered from end-use consumers. When a commission determines an amount qualifies as an extraordinary item, it reviews potential recovery on a case-by-case basis. The commission may choose to approve a portion of the amount for recovery and set parameters for when the amount may be recovered. Under the 2026 ASCM, the results of that commission analysis would become an input into a utility's ASC. Amounts above the 5% threshold would be included, if supported by state commission orders and pursuant to the recovery timeframe in such orders. If the state commission does not allow recovery, then such amounts would not be included in ASC.

BPA also intends to implement the logic of General Instruction 7 to look at "5 percent of income, computed before extraordinary items." BPA will likewise define the threshold metric as "5 percent of income, *computed before Account 925 costs*." That is, the utility's net income will be modified to add back in the costs associated with Account 925. This tracks with the way "extraordinary items" are computed in General Instruction 7, and with how the Montana PUC determines materiality. BPA refers to this metric as the "5% of the utility's modified net income."

More specifically, the ASCM will use the following formula to determine whether the costs included in ASC exceed the intended threshold:

$$\frac{\text{925 Functionalized to Production (Appendix 1)}}{\text{(Total 925(FERC Form 1) + Net Income before Extraordinary Items(FERC Form 1))}}$$

BPA evaluated the revised proposal using 19 years of historical data from the IOUs' FERC Form 1 filings. As anticipated, only PacifiCorp's 2023 filing triggered the provision.[561] Although this historical analysis indicates the new proposal broadens the original 1% threshold, it does so in alignment with other "extraordinary" items that can impact a utility's FERC Form 1 inputs.

[560] 18 C.F.R. Part 100, General Instruction 7.
[561] *See* Historical 5 Percent Net Income Threshold – 2007-2026, Sep. 11, 2026, on file with author.

2. *Response to parties' comments in light of the modified threshold proposal*

The remainder of this evaluation addresses stakeholder comments on the February 2026 version of the ASCM. While BPA's decision to revise the 1% threshold renders some of these issues moot, other comments remain relevant and are addressed below where appropriate.

3. *Whether BPA's proposal impermissibly limits costs in ASC*

The IOUs and WUTC object to Staff's proposal as "limit[ing]"[562] Account 925 costs through a "cap" or "maximum threshold."[563] The IOUs argue that "[b]ecause the NWPA does not authorize BPA to carve out or otherwise limit injuries and damages costs, BPA lacks authority under the plain text of the NWPA to categorically restrict or limit recovery of Account 925 costs."[564] The WUTC argues, "BPA's proposal to limit these costs in excess of 1% artificially caps expenses related to Injuries and Damages that IOUs are reasonably expected to incur as extreme weather events, storms, and wildfires continue to increase in Washington."[565] Conversely, Public Power customers argue that "BPA retains discretion to exclude costs beyond those categories specifically enumerated in [NWPA] § 5(c)(7)," including Account 925 costs.[566]

Fundamentally, BPA's proposal is *not* excluding Account 925 costs that exceed the threshold discussed above. BPA's proposal is a methodology that creates a process for *how* and *when* to include costs associated with injuries and damages. The methodology includes a process to include all injuries and damages costs that the state commissions include for rate recovery. The threshold merely requires additional documentation—FERC Form 1 would be sufficient for amounts below the threshold; state commission orders would be needed when amounts are above the threshold.

The IOUs argue, "under the NWPA, all Account 925 costs must be eligible for inclusion in the ASC . . . ."[567] Contrary to this assertion, the Northwest Power Act does not require that every value entered into FERC Form 1 must be included in the "average system cost" of a utility's resources. The statute does not require use of the FERC Form 1. Indeed, prior to the 2008 ASCM, BPA used a jurisdictional approach that looked to the costs allowed to be recovered by state commissions. Under a purely jurisdictional approach, the methodology would include only injuries and damages costs deemed recoverable by state commissions. BPA is not excluding costs. BPA's methodology uses FERC Form 1 data and state commission determinations as to the process for including costs related to injuries and damages. The methodology strikes a balance between (1) relying on the expertise of state commissions in fact-finding and policy considerations regarding whether and when the

[562] IOU Comments (April) at 11.
[563] WUTC Comments (April) at 4.
[564] IOU Comments (April) at 11-12.
[565] WUTC Comments (April) at 5.
[566] Public Power Comments (April) at 11.
[567] IOU Comments (April) at 12.

cost of injuries and damages can be recovered, and (2) the administrative burden of a jurisdictional approach.

The only excluded costs would be those exceeding the 5% threshold that state commissions have disallowed (or otherwise not shown to be recoverable) from retail ratepayer recovery. The IOUs refer to such costs as "legitimate system costs."[568] They may well be. BPA is not stating that costs exceeding the 5% of the utility's modified net income must be excluded from ASC for all time. Instead, BPA requires additional documentation for these costs. Until this documentation is provided, such costs must be omitted from the utility's ASC.

The IOUs argue that excluding "large and statistically uncommon" costs "is an arbitrary standard" because "[s]tatistically uncommon costs can occur in any of the FERC Form 1 accounts . . . ."[569] Again, BPA is not excluding large and statistically uncommon costs. BPA is setting a threshold beyond which an additional process is required to include legitimate injuries and damages costs. It reflects how state commissions may treat such costs, determining whether and when such costs can be recovered. Additional scrutiny is reasonable where state commissions have been exercising such scrutiny, and where there is a meaningful potential for disallowed costs to drive an exchanging utility's ASC.

Indeed, BPA has, in other parts of the ASCM, required a closer examination of accounts with potentially large costs that depend on state commission approvals. For instance, the 2008 ASCM mandated that utilities provide state utility commission orders allowing them to recover regulatory assets and liabilities in retail rates before including these costs in a utility's ASC.[570] For regulatory assets, BPA explicitly stated that "[u]nder no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates."[571] This requirement was implemented because, for some utilities, regulatory assets and liabilities "represent a significant amount of costs in the FERC Form 1."[572] BPA's current proposal for Account 925 is similar. Just as regulatory assets and liabilities can show one number in the FERC Form 1, while regulators approve another, Account 925 can also have a reported number that differs from what state regulators approved. BPA's proposal to require state commission approval for certain injuries and damages aligns with the same logic used in the 2008 ASCM for regulatory assets and liabilities. This approach strikes the proper balance between ensuring the utility's resource costs reflect legitimate costs associated with operating its utility, and avoiding a return to the burdensome jurisdictional approach.

The WUTC states, "BPA's proposal to limit these costs in excess of 1% artificially caps expenses related to Injuries and Damages that IOUs are reasonably expected to incur as

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[568] *Id.* at 11.
[569] *Id.* at 12.
[570] *See* 2008 ASCM ROD at 149. This requirement was established in the narrative section of the 2008 ASCM ROD regarding regulatory assets and liabilities. Given its importance, BPA has updated the 2026 ASCM to include a new section, 301.4(z), to codify these requirements.
[571] *Id.* at 149.
[572] *Id.* at 150.

extreme weather events, storms, and wildfires continue to increase in Washington."[573] As noted above, BPA is revising the metrics for its threshold. Even so, BPA has proposed that the method for including Account 925 costs above 5% of the utility's modified net income is to submit materials demonstrating that the WUTC has approved such injuries and damages for retail rate recovery. If the WUTC believes it was reasonable and prudent for the utility to incur these costs, such that they are recoverable from Washington ratepayers, they will be able to be included in the utility's ASC. Moreover, state commissions will be aware that their approval is needed to include very large amounts of injuries and damages in a utility's ASC, and can make findings accordingly. Far from being an "artificial cap," BPA's methodology relies on the WUTC to *be* the cap.

Further, Public Power correctly argues that "BPA retains discretion to exclude costs beyond those categories specifically enumerated in § 5(c)(7)."[574] BPA agrees that it has discretion to adopt a methodology that excludes these costs.

4. <u>Whether 2026 ASCM impermissibly includes costs in ASC.</u>

Public Power objects that BPA's proposal could result in more injuries and damages being included in a utility's ASC than are approved for recovery by a state commission. Public Power argues, "[i]t is plausible — if not likely — that part or all of such costs: (1) are the result of a utility's gross negligence; (2) were caused by utility assets functionalized to transmission or distribution; and/or (3) have not been granted cost recovery from the relevant state commissions."[575] BPA acknowledges this is a potential outcome. However, BPA has limited the exposure of this risk and balanced it in the context of the practical realities of state ratemaking and administrative burden. BPA's proposal strikes a reasonable balance.

The IOU and WUTC comments speak to these practical considerations. The IOUs, in criticizing BPA's limited reliance on state commission approvals, argue that BPA's proposal "is not aligned with realities of retail ratemaking" because "PUCs routinely issue rate decisions without making explicit line-by-line findings on every cost a utility incurs."[576] The WUTC argues, "utilities and their respective regulatory commissions will need to spend additional time to provide the specific documentation requested by BPA."[577]

BPA recognizes that state commissions may not individually address smaller items or more normal overhead expenses. State commissions may approve rates as black box settlement packages, which may reflect injuries and damages among several other disputed issues. These realities could make it burdensome or impractical to provide approval documentation. BPA also recognizes that there is an element of rough justice in adopting a FERC Form 1 approach for calculating a utility's ASC, and that there is value in a streamlined, less administratively burdensome process. As BPA Staff stated:

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[573] WUTC Comments (April) at 5.
[574] Public Power Comments (April) at 11 (citing *PacifiCorp,* 795 F.2d at 823).
[575] *Id.* at 10-11.
[576] IOU Comments (April) at 12.
[577] WUTC Comments (April) at 5.

> The intent is for "normal" Account 925 costs to automatically flow into ASC via the LABOR ratio, and avoid the complexity of a jurisdictional approach where specific items may not regularly be called out in commission orders. However, very large and statistically uncommon damages should require a closer look. This reflects the scrutiny of such costs by state commissions in choosing whether and how to allow retail rate recovery.[578]

In most circumstances, BPA's proposal regarding injuries and damages will operate as it did under the 2008 ASCM. This general overhead expense will flow into ASC without additional state commission documentation. However, BPA has significantly limited the potential for disallowed injuries and damages to drive a utility's ASC. When this overhead expense is driving a utility's ASC—representing more than 5% of the utility's modified net income—more scrutiny is appropriate. State commissions will likely be wrestling with whether and when a cost of such magnitude should be recovered from ratepayers, considering the facts surrounding the utility incurring such costs, and making policy-laden determinations. While there may be an administrative burden beyond the state commission's status quo ratemaking, the magnitude of including such costs in a utility's ASC will incentivize utilities and state commissions to document their treatment. Further, additional work is a reasonable prerequisite to mitigate BPA's Public Power customers having to pay for IOU costs that IOU consumers will not have to pay.

Commenters provide no evidence that state commissions regularly disallow all or most Account 925 costs, or that Account 925 costs regularly account for a significant portion of a utility's Contract System Cost. Therefore the $80 million value cited by Public Power[579] is largely irrelevant. Actual Account 925 costs are generally lower than 5% of the utility's modified net income, and even below BPA's original 1%[580], and such costs are likely being paid by retail ratepayers as well.

5. <u>Whether the 2026 ASCM should exclude certain injuries and damages costs resulting from wildfires.</u>

Public Power customers and AWEC argue that wildfire damages, in particular, should be excluded from a utility's ASC.[581]

As discussed above, when injuries and damages exceed 5% of a utility's modified net income, it is reasonable to assume state commissions will be wrestling with questions of negligence, causation, prudency, and affordability. These are potentially very difficult questions. BPA believes it is appropriate for the methodology to avoid creating a process where BPA must make independent determinations on these questions. While BPA is unwilling to simply allow all recorded costs in Account 925 to flow into a utility's ASC, BPA is leveraging the state commission's expertise in this area.

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[578] BPA Staff Clarification to Draft 2026 ASCM, Feb. 20, 2026; ASCM Workshop 5, Feb. 13, 2026.
[579] Public Power Comments (April) at 10 ("In BP-26, for example, 1% of the IOUs Contract System Costs totaled roughly $80 million.").
[580] BPA Staff Clarification to Draft 2026 ASCM, Feb. 20, 2026; ASCM Workshop 5, Feb. 13, 2026.
[581] Public Power Comments (April) at 11; AWEC Comments (April) at 7.

For example, Public Power customers argue, "BPA should categorically exclude from the ASCM any and all wildfire liability costs incurred by the IOUs arising from their distribution or transmission functions."[582] Causation itself is a fact-intensive issue. Assigning that causation to a specific function, beyond the responsible legal entity, is a further fact-intensive issue. Account 925 is a single Administrative and General account, and is not functionalized to Production, Transmission, and Distribution. BPA's methodology addresses the issue of functionalization by applying a functionalization ratio to this account, as it does with other A&G accounts. Through this ratio, the ASCM is excluding Account 925 costs associated with Transmission and Distribution.

AWEC argues that, even if wildfire liability costs were approved by a state commission, "wildfire liability costs resulting from a utility's gross negligence should not be included in the calculation of a utility's ASC."[583] Gross negligence is a fact-intensive issue. This determination may seem straightforward when a jury has rendered a verdict with specific findings of gross negligence, but would be more difficult if the injuries and damages took the form of paying a no-fault settlement. This would be true even if the overwhelming likelihood of being found negligent at trial led the utility to seek such a settlement.

Public Power customers specifically argue against the inclusion of wildfire damages to avoid BPA becoming, through the REP, "the deep pocket insurer of last resort for the IOUs . . . ."[584] BPA's methodology provides balanced protection against that result. When injuries and damages exceed 5% of a utility's modified net income, the state commission determinations limit what can be included in a utility's ASC. The state commission's primary consideration will likely not be on the potential impact to REP benefits, but on the direct impact to the retail ratepayers in its jurisdiction. Allowing imprudently incurred costs to be recovered by retail ratepayers in order to marginally increase REP benefits would be the tail wagging the dog. Conversely, if a state commission determines—after weighing the facts and policies—that certain injuries and damages are the "cost of doing business" and properly recoverable from retail ratepayers, then BPA would defer to that determination under the methodology.

6. *Whether requiring state approval is unreasonable because of timing mismatches and regulatory lag.*

The IOUs argue, "[r]eliance on retail rate recovery introduces unnecessary variability among utility rates and regulatory lag, which can be avoided through reliance on uniform and annually-updated utility accounting forms at FERC."[585] The WUTC argues, "the requirement to obtain further Commission guidance may result in timing mismatches between rate cases and ASC reporting periods" and that "additional time to provide the specific documentation requested by BPA…may result in a scenario where the parties do

[582] Public Power Comments (April) at 11.
[583] AWEC Comments (April) at 7.
[584] Public Power Comments (April) at 11.
[585] IOU Comments (April) at 12.

not have the necessary time to provide the information BPA requires before the ASCs are calculated, creating regulatory lag."[586]

Given the reasonableness of requiring additional scrutiny for very large injury and damages amounts, BPA disagrees that the potential for regulatory lag would make its proposed methodology unreasonable. Moreover, what the IOUs and WUTC term "regulatory lag" is arguably a beneficial feature of BPA's proposal. BPA's methodology would *better* align a utility's ASC with the rates experienced by its end-use consumers. This could be due to state commissions excluding such costs from retail rate recovery, or a timing mismatch.

For example, state commissions may determine, not just *whether,* but *when* a utility may recover injuries and damages. They may delay recovery to consider the matter more thoroughly, or to wait until there is greater factual certainty. If a state commission deferred but later approved retail rate recovery of such costs, the ASC could be very high upfront, but much lower at the time retail rates increase to recover such costs. Or a commission may determine that the amount should be recovered over time, rather than in a single year. In such cases, it is not an inappropriate "regulatory lag" to wait for state commission determinations and to reflect them in a utility's ASC. To the contrary, it could be unreasonable to (1) include a very large injuries and damages cost, in a single year, in a utility's ASC—providing REP benefits when the end-use consumers are not yet experiencing those costs in their retail rates; and then (2) have no corresponding REP benefit in later years when injuries and damages costs are increasing their retail rates. BPA's proposal *better* aligns REP benefits with when end-use consumers experience higher rates.

7. *<u>Whether all Account 925 costs should be allowed in ASC to achieve symmetry with BPA ratemaking.</u>*

The IOUs argue "[w]hile BPA apparently has no problem restricting participating utilities from including these legitimate costs, BPA admitted during its February 13, 2026 workshop that if it were to incur similar costs, it would recover such costs in its rates. Apparently for BPA, it only advocates for symmetry if it benefits itself."[587]

BPA's own treatment of any such liability is consistent with, not in conflict with, its approach for the 2026 ASCM of similar costs. Just like the IOUs, how and when BPA recovers the costs of any damages related to wildfire liability in its rates would be a rate case issue decided by the Administrator. Once approved in a rate case, BPA would have "regulatory approval" of these costs, just as the proposed ASCM would require from IOUs. Any difference simply reflects the difference in IOU status as state-jurisdictional utilities and BPA's status as a federal power marketing administration.

Further, the functionalization of these costs would be a rate case issue. If costs were functionalized to Transmission, they would be excluded from the rates BPA charges its

[586] WUTC Comments (April) at 5.
[587] IOU Comments (April) at 12.

power payers, including the IOUs who pay the PF Exchange rate for purposes of the REP. In the same way, if state commissions disallowed the utility from recovering damage costs from their retail rate payers, those costs would be excluded from the utility's ASC. BPA's treatment of injuries and damages costs in its rates is reasonably symmetrical to how such costs would be treated in ASCs.

8. *Whether all Account 925 costs should be allowed in ASC because Account 925 costs are included in some FERC-approved formula rates.*

The IOUs state, "Account 925 costs are commonly included in FERC-approved formula rates."[588] It is unclear what argument IOUs are making with this statement. Account 925 costs will commonly be included in ASCs under BPA's proposed methodology. Conversely, imprudently incurred Account 925 costs can be challenged under FERC-approved formula rates. BPA notes that it is currently challenging PacifiCorp's inclusion of certain Account 925 costs under its FERC-approved transmission formula rate. Regardless of the outcome of that specific challenge, there is a basis for challenging imprudently incurred costs. Inclusion in Account 925 does not guarantee rate recovery. That is, as with BPA's proposed ASCM, the "methodology" of FERC transmission formula rates allows the exclusion of certain Account 925 costs.

Finally, FERC-approved *transmission* formula rates are less relevant to the ASCM, which as discussed in *Issue 3.5.1*, is concerned with the cost of "resources" as defined by the Northwest Power Act.

Draft Decision

BPA's treatment of injuries and damages in the ASCM is consistent with statute and otherwise reasonable. BPA will apply a 5%-of-modified net-income threshold to Account 925, above which state commission orders showing recovery by end-use consumers are required to allow such costs into a utility's ASC.

5.8.8 Transmission Costs in FERC Accounts 565 and 447 (CFR § 301.4(x))

The 2026 ASCM excludes transmission costs from ASC, except for those costs recorded in Transmission of Electricity by Others, Account 565, and transmission (delivery) costs associated with Sales for Resale, Account 447.

FERC Account 565 includes costs for payments made to others for the transmission of the utility's electricity over transmission facilities owned by others. Transmission O&M is not included in ASCs, but Account 565 is backed out of transmission and functionalized to Production.

FERC Account 447 includes the net revenues from electricity sold for resale to other utilities. Transmission or delivery costs associated with sales for resale in Account 447 may be recorded in a separate line item and functionalized by Direct Analysis.

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[588] *Id.*

5.8.9 Demand-Side Management / Demand Response (CFR § 301.4(y))

BPA does not consider demand-side management (DSM) or demand response (DR) to be conservation measures; however, BPA recognizes that some measures may be conservation-related. DSM and DR costs recorded in Account 908 may be functionalized by a Direct Analysis. When doing so, the utility must provide sufficient supporting documentation demonstrating that such costs are Production-related.

6.0 EXCHANGE PERIOD AVERAGE SYSTEM COST (CFR § 301.5)

6.1 Overview and ASC Forecast Model

As noted earlier, the 2026 ASCM retains the structure of the 2008 ASCM, in which a Base Period ASC is calculated from historical information using the utility's FERC Form 1. Certain components of this information are then escalated to the Exchange Period, which is concurrent with BPA's rate period. The model that performs the escalation from the Base Period to the Exchange Period is called the ASC Forecast Model. The 2026 ASC Forecast Model is a revised version of the model used under the 2008 ASCM and shares significant portions of the same layout and functionality.

6.2 2026 ASC Forecast Model Modernization

To properly reflect the terms of the 2026 ASCM, BPA modernized and updated the ASC Forecast Model ("2026 ASC Forecast Model"). Described below are major changes in the Excel model developed to reflect the 2026 ASCM. The ASC model has been revised and updated based on the new 2026 ASCM as well as to remove macros from the workbook.

<u>*Macro Removal*</u>

The original ASC Forecast Model from the 2008 ASCM used a series of macros to conduct the calculations and escalations required by the ASCM. Macros have fallen into disuse, largely because they are a burdensome feature in Excel models. In addition, macros often require special user permissions and/or had to be run in isolated versions of Excel. Frequently, users would find that downloaded versions of the model would have macros removed due to security constraints particular to their organization. In view of these technical issues, macros have been removed from the 2026 ASC Forecast Model. Cells are now linked through ordinary Excel references and formulas.

<u>*Tabs Removed*</u>

A number of tabs from the prior 2008 ASC Forecast Model have also been removed, to reflect changes made in the 2026 ASCM. These include the following tabs:

- *Natural Gas Market Prices* (This was an extraneous page. Natural gas prices are now directly included in the Inputs tab).
- *Above-RHWM Base* (not used in 2026 ASCM).
- *Above-RHWM Esc* (not used in 2026 ASCM).
- *Prod+Tran* (not used in 2026 ASCM).
- *Tiered Rates* (not used in 2026 ASCM).

6.3 Escalating the Base Period ASC to the Exchange Period ASC with Escalation Codes (CFR § 301.5(a))

Section 301.5(a) of the 2026 ASCM describes the methods, source data, and codes that escalate data from the Base Period to the Exchange Period.

6.3.1 Escalation of the Base Period ASC to Exchange Period ASC (CFR § 301.5(a)(1)-(2))

The 2008 ASC Forecast Model employed intricate macros to derive escalation rates for cost forecasting. It used an Inputs tab, populated with forecast escalation values from various sources, which then fed into an Inputs Monthly tab to convert annual forecasts into monthly escalator values. The model assigned specific dates to calculate forecasted ASCs, with the table constructed using cumulative escalation values for each functionalization code. Excel formulas then populated columns corresponding to relevant dates to build costs on the Total & Functionalization Tab.

The 2026 ASC Forecast Model avoids this complexity entirely. The 2026 ASCM removes the macros and relies on Excel formulas instead. Columns now exist for each month following the Base Period and continuing through the end of the Exchange Period. Redundant columns are avoided by summing new resource costs, in the case of concurrent new resource online dates, in the new resource addition columns specific to a given month on the Total & Functionalization tab.

6.3.2 Escalation Codes Defined (CFR § 301.5(a)(3)-(7), and Table 1)

Escalation codes are used in forecasting future costs based on Base Period data from the Appendix 1. Much like an actual escalator, escalation codes can go up and down, and may be either positive or negative. Escalation codes can be non-linear (*e.g.,* negative in the near-term and positive in the long-term). Most escalation codes are sourced directly from a third party. The natural gas price forecast and the short-term purchase and sale prices similarly rely on external data. The natural gas price forecast is produced by BPA using third-party data. Market data is used in calculating the short-term purchase and sale price forecast.

6.4 Escalating Sales for Resale and Power Purchases in the Exchange Period ASC (CFR § 301.5(b))

To escalate purchases and sales from the Base Period, the model utilizes the load forecast from the Appendix 1. The subject utility is assumed to be in load resource balance in the Base Period. That is, the Base Period actual load is served by generating resources and power purchase actuals in the Base Period. In future periods, an increase in loads, as indicated by the load forecast, will be served by power purchases. Any decrease in load would conversely trigger sales in the Exchange Period, with the resulting sales treated as Sales for Resale.

Described below are the long-term, intermediate, and short-term purchases and sales. Long-term and intermediate sales and purchases are treated differently than short-term purchases and sales. This modeling assumption addresses disparate functions within the model detailed below.

6.4.1 Long-Term and Intermediate Sales for Resale and Power Purchases (CFR § 301.5(b)(1))

Power purchase and sales are forecast on the OSS & PurPwr Forecast tab of the 2026 ASC Forecast Model. This tab consists of a large table of calculations designed to purchase or sell power as necessary to address changes in the load forecast (drawn in from Appendix 1).

New power contracts (in contrast to short-term market purchases) are included in the new resource tab of the Appendix 1 and grow at the rate of the escalation code INF. New long-term and intermediate power purchases and sales, if present, are first netted against any changes in load as derived from the subject utility's load forecast. Remaining deficits and surplus are served by forecast short-term power purchases and sales.

6.4.2 Short-Term Sales for Resale and Power Purchases (CFR § 301.5(b)(2))

Short-term purchases and sales forecast computations are the final modeling step necessary to tie the load forecast to Exchange Period costs. For short-term sales for resale and power purchases, the Base Period price and quantities serve as starting points, creating utility-specific forecasts for pricing. The ASCM employs a specific method to determine market prices for forecasting, which involves calculating the utility's average short-term purchase and sales prices in the base period, finding the midpoint, and then applying a weighted average spread from the last three years of data to the calculated midpoint. This midpoint and weighted spread are then escalated through the Exchange Period and used to set the purchased power and sales for resale prices for the Exchange Period ASC.

6.4.3 Issues

<u>Issue 6.4.3.1</u>

Whether the methodology for determining the price of power used for serving load growth and valuing Sales for Resale in the ASC Forecast Model is reasonable.

<u>BPA Staff's Proposal</u>

The 2026 ASCM retained the same methodology for determining the cost of serving load growth as in the 2008 ASCM. Section 301.5(e) states that the utility's forecast load growth will be met "with electric market purchases priced at the Utility's forecast short-term purchased power price as determined in paragraph (b) of this section unless the Utility forecasts major resource additions." Section 301.5(b) provides a specific method for determining the short-term sales for resale and power purchase price.

<u>Parties' Positions</u>

The IOUs argue that BPA's method for forecasting electric power prices for load growth is flawed.[589] The IOUs contend that the method in the 2026 ASCM systematically understates

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[589] IOU Comments (April) at 13-14.

costs by assuming incremental load can be served at unrealistically low market prices.[590] They contend that this approach in the 2026 ASCM ignores how utilities actually procure power and fails to account for stringent environmental requirements, leading to prices inconsistent with market realities.[591] While acknowledging the uncertainty in forecasting, the IOUs claim BPA's method is unreasonable.[592] The IOUs do not provide a specific suggestion, but rather recommend BPA develop a "reasonable floor" on forecasted purchased power prices to accurately reflect the cost of serving unmet load growth.[593]

Public Power customers oppose BPA's shift from a 5-year to a 3-year average for calculating the exchanging utility's short-term power purchase price, arguing it is inconsistent with standard utility ratemaking principles, which prioritize stability for long-run incremental costs.[594] They contend that a 3-year average is more susceptible to short-term market fluctuations and weather events, leading to instability in ASC and REP benefits.[595] The Public Power customers highlight that BPA's original proposal used a 5-year average, which they believe dampens volatility and aligns better with these ratemaking principles, producing more stable and predictable results.[596] They also point out an inconsistency in BPA using different averaging periods for various calculations and suggest that a longer, 5-year weighted average would enhance model stability, especially given the known sensitivity of the REP model to input changes.[597]

Evaluation of Positions

As described in section 3.3.2.1.1 of this ROD, a utility's Base Period ASC is determined from after-the-fact actual data from a utility's FERC Form 1, including actual resource cost and load data. Consistent with the 2008 ASCM, the 2026 ASCM "escalates" certain values from the Base Period ASC to the rate period over which the utility will participate in the REP, also known as the Exchange Period. One area in the Base Period where historical values are updated is the purchase price for Sales for Resale and power purchases. Sales for Resale are sales of power from the utility to other entities.[598] Sales for Resale generally appear as a credit in the utility's ASC. Power purchases, as its name implies, are power purchases by the utility, and generally appear as a cost in a utility's ASC.

One challenge in using historical Base Period energy prices is accurately reflecting what power prices to use in the Exchange Period, which occurs over a year later. This complexity is compounded by the fact that utilities are not consistently net purchasers or sellers of power. For example, a utility might have uncharacteristically high power purchase costs in the Base Period due to buying large amounts at high market prices, while

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590 *Id.* at 14.
591 *Id.*
592 *Id.*
593 *Id.*
594 Public Power Comments (April) at 15.
595 *Id.* at 16.
596 *Id.*
597 *Id.*
598 *See* FERC Glossary, Sales for Resale, *available at* https://ferc.gov/industries-data/resources/public-reference-room/ferc-glossary.

another might have significant Sales for Resale credits from selling power at similarly high prices. If BPA were to keep these energy prices static through the Exchange Period, the net-purchasing utility would benefit from higher recorded power purchase costs in its ASC, while the net-selling utility would be disadvantaged by higher Sales for Resale credits. Conversely, if Base Period market prices were uncharacteristically low but Exchange Period forecasts show an increase, the situation would reverse.

The 2008 ASCM addressed this issue by creating a price spread built from the utility's actual purchased power costs and Sales for Resale credits.[599] This price spread used the utility's "most recent three years of actual data (Base Period and prior two years)."[600] A midpoint between the average high and low prices is calculated, weighted, and then escalated (or deescalated) at "the same rate as Bonneville's electric market price forecast."[601] Significantly, the resulting price from this calculation is used to estimate the "electric market price for power purchases needed to meet load growth not met by major resource additions, and to forecast the electric market price for any additional surplus power sales resulting from major resource additions."[602] The resulting prices from these calculations would be used to value the short-term purchases (costs) and short-term Sales for Resale (credits) in the utility's Exchange Period ASC.

In the 2026 ASCM, BPA proposed to retain this method for calculating the energy prices for short-term power purchases used to serve load growth and to estimate the credits associated with Sales for Resale for the Exchange Period.[603]

Both the IOUs and Public Power customers identify concerns with BPA's decision to retain the 2008 ASCM's approach. As the nature of these concerns differs, BPA addresses them under separate headings below.

1. <u>IOU Concerns: Adopt A New Forecasting Method.</u>

The IOUs contend that BPA's method for forecasting prices for electric power to serve load growth is faulty.[604] The IOUs argue that this approach to calculating the costs of meeting load growth "systematically understates the cost of serving load growth not met by new resources."[605] They assert that the 2026 ASCM uses an assumption that "incremental load can be served at extremely low market prices [that] does not reflect how utilities actually procure power and results in ASCs that are not representative of underlying costs."[606] The IOUs explain that market prices "ignore[] the increasingly stringent environmental requirements imposed on utilities that typically cannot be met through market purchases."[607] These low prices are then applied across the Exchange Period, resulting in a

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[599] *See* 18 C.F.R. § 301.4(b)(2).
[600] *Id.* § 301.4(b)(2)(ii)(A).
[601] *Id.* § 301.4(b)(2)(ii)(C)-(F).
[602] *Id.* § 301.4(b)(2)(iii).
[603] 2026 ASCM § 301.5(b)(2).
[604] IOU Comments (April) at 13-14.
[605] *Id.* at 14.
[606] *Id.*
[607] *Id.*

price that is "inconsistent with market realities and environmental requirements" and "understates purchase power costs" that materially affects the calculation of ASC and REP benefits.[608] The IOUs acknowledge forecasting future market prices is "uncertain," but then claim the approach used in the ASCM Forecast Model is "not reasonable" and does "not align with utility experience."[609] The IOUs recommend BPA revise the existing methodology and "at a minimum, establish a reasonable floor on forecasted purchased power prices to ensure that the cost of serving unmet load growth is not understated."[610]

BPA appreciates the IOUs' concerns regarding the pricing method in the 2008 ASCM and has explored alternative methods for projecting energy prices from the Base Period into the Exchange Period. However, BPA has found inherent methodological issues with almost every alternative considered.

For example, simply holding prices static from the Base Period could unreasonably assume that a utility's past energy prices will continue. This assumption is problematic if a utility spent very little on purchased power in the Base Period but anticipates purchasing significantly more at higher prices in the Exchange Period. Conversely, if a utility received substantial credits for Sales for Resale due to high market prices in the Base Period (which would reduce its ASC), it may be unrealistic to assume those same large credits will persist into the Exchange Period (reducing its Exchange Period ASC as well). Using fixed escalators or adjusters would result in similar problems.

Further complicating matters is the necessity of developing a pricing forecast method applicable to all exchanging utilities. A method that is effective for one utility might not suit another, as each utility has a unique position—some are net purchasers, others net sellers—along with distinct marketing strategies and energy profiles. Ultimately, BPA must adopt an approach that accounts for changing prices (escalation and de-escalation) and each utility's distinct energy position (some long, some short). The method BPA proposes to use in the 2026 ASCM does this adequately.

The IOUs argue that BPA's approach is unreasonable because it is "inconsistent with market realities and environmental requirements" and "understates purchase power costs," which materially affects the calculation of ASC and REP benefits.[611] However, the IOUs' argument itself highlights the problem BPA has identified with alternative approaches: from what perspective is the 2026 ASCM "understating" the utility's power purchase costs? The IOUs merely assert that Base Period costs (and credits) serve as a "reasonable" proxy without any justification for this position. This seems to stem from the fact that, in recent years, prices derived from the Base Period have tended to be higher than prices escalated through the Exchange Period. This outcome, however, is not a foregone conclusion; just as Base Period prices can be higher than Exchange Period prices, the opposite could also be true. While BPA understands the nature of the IOUs' concerns, BPA does not agree that reacting to recent market price volatility requires abandoning the

608 *Id.*
609 *Id.*
610 *Id.*
611 *Id.*

current method. The current method reasonably links the utility's actual costs for purchased power and Sales for Resale to market realities, while acknowledging each utility's unique energy position.

To that end, the IOUs do not seem to recognize that limiting Exchange Period market values in some way to Base Period market values would affect individual IOU ASCs differently, with some increasing and others decreasing. These discrepancies would arise, not because these values better reflect the IOUs' costs and credits during the Exchange Period, but because BPA would be assuming that the utility's past costs and credits are a proper reflection of its future costs and credits.

For example, BPA analyzed Avista's 2023 Base Period ASC as a test case, since this utility routinely has high Sales for Resale credits in its Base Period ASC.[612] For this ASC Review Period, (FY 2026-2028), Avista had a net credit in its Base Period ASC of approximately $37 million due to high amounts of credits associated with Sales for Resale. Moving into the Exchange Period, these values flipped, with Avista's power purchases exceeding its Sales for Resale credits, resulting in net power purchase costs in Avista's Exchange Period ASC of about $60 million. If BPA simply used the power purchase costs and Sales for Resale values from the Base Period in Avista's filing, the Sales for Resale credits Avista experienced in its Base Period ASC would continue forward (at a lesser amount) in the Exchange Period ASC, reducing Avista's Exchange Period ASC by an additional $23 million in Sales for Resale credits. In simple terms, by holding Base Period power prices static, Avista's Exchange Period ASC would have swung from being a net purchaser of power ($60 million cost in its ASC) to a net seller of power ($23 million credit to its ASC).[613] For Avista, this single change would mean dropping its resource costs by over $80 million, reducing its ASC (all else equal) from $56.86/MWh to $48.14/MWh.[614] The below chart illustrates this outcome.

Avista (standard method & alternative)			
	Base	Exchange (std)	Exchange (Alt)
Short Term Purch Price	$116	$50	fixed to base
Total Power Purchases	$216m	$189m	$233m
Short Term Sale Price	$86	$34	fixed to base
Total Sales for Resale	$254m	$128m	$257m
Net Purchase & Sale		$61m	-$24m
Exchange ASC		$57/MWh	$48/MWh

[612] *See* Avista Base ASC Example, Sep. 11, 2026 (on file with author).
[613] *Id.*
[614] *Id.*

While such an outcome might be reasonable if supported by sound methodological reasoning, the IOUs' rationale seems to be solely that the Base Period values are (currently) higher and thus warrant greater consideration. The simplified example shows the problem of such a myopic approach. Furthermore, as previously noted, BPA's current method does not necessitate a result where historical prices are lower than current prices, and future market prices could reverse this outcome.

The IOUs do not offer a solution to the concerns they raise, but instead, recommend that BPA revise the existing methodology and "at a minimum, establish a reasonable floor on forecasted purchased power prices to ensure that the cost of serving unmet load growth is not understated."[615] The IOUs offer no detail on how such a "reasonable floor" could be constructed. Moreover, an approach that sets a floor leads to the unusual result of BPA locking in one side of the market price equation (purchase power costs) while leaving the other side (Sales for Resale credit) open. The two are interrelated, and BPA finds no logical reason to create a floor for one while leaving the other susceptible to market fluctuations.

The current method in the 2008 ASCM, which is included in the 2026 ASCM, provides a reasonable approach that accounts for prices and costs that are difficult to forecast. While BPA acknowledges that its proposal is not perfect, it believes that it reasonably offers a uniform approach for forecasting prices based on each individual utility's actual purchase power and Sales for Resale data. Moreover, the IOUs have not offered a viable alternative.

Considering the points above and in the spirit of collaboration, BPA has developed an alternative to the method currently proposed in the 2026 ASCM. This alternative, discussed under heading three below, aims to address some of the IOUs' underlying concerns without creating the additional problems mentioned in this issue. BPA views this alternative as a potentially comparable approach to the method currently in the 2026 ASCM. BPA is seeking stakeholder feedback on the viability of this alternative.

2. <u>Public Power Customers' Concerns: 5-year vs. 3-year Average Price.</u>

Public Power customers oppose BPA's proposal to use a 3-year basis for the exchanging utility's average short-term power purchase price, as opposed to a 5-year average.[616]

By way of background, in the preliminary draft ASCM, BPA proposed to modify its approach to calculating power purchase costs in the ASC Forecast Model by using a 5-year period to determine the average short-term power purchase price.[617] The IOUs submitted preliminary comments objecting to this treatment, requesting that BPA retain its 3-year average.[618] In the February 2026 draft of the ASCM, BPA agreed to retain the 3-year average.[619]

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[615] IOU Comments (April) at 14.
[616] Public Power Comments (April) at 15.
[617] Preliminary Draft 2026 ASCM, Dec. 10, 2025, § 301.5(b)(2)(ii)(A).
[618] IOU Comments on Preliminary ASCM Draft, Jan. 21, 2026, at 5-6.
[619] Incremental Draft 2026 ASCM, Feb. 3, 2026, § 301.5(b)(2)(ii)(A).

Public Power customers contend this proposal is "inconsistent with normal utility ratemaking standards."[620] They note that the ASC Forecasting Model performs a "rate-making exercise."[621] Public Power customers note that while a 3-year average may be appropriate for "auditing, financial reporting, and regulatory compliance purposes," it is not reasonable for setting rates where long-run incremental costs are used for "stability and predictability in utility rate making."[622] They argue that a 3-year historic value will be more "reactive" to short-term fluctuations in supply, demand, and other volatilities.[623] Public Power customers contend that weather-driven events (cold snaps or dry years) can swing the IOUs "Sales for Resale" account, and therefore, the utility's resulting ASC and downstream REP benefits.[624] They also cite Bonbright for the principle that rate stability and predictability are guiding principles of utility ratemaking.[625]

While BPA agrees that, as a matter of rate principles, stability is a sensible feature, ASCs are "not traditional [Federal Power Act] rates, even though the Commission will review them under the FPA."[626] Thus, BPA finds that the discretionary principles noted by Public Power customers do not compel BPA to return to the 5-year average. The 3-year average has been in place since the 2008 ASCM was developed, and over that time it has performed well in maintaining relatively stable prices for utility ASCs.

To that point, while Public Power customers note that 5-year averages "dampen short-term fluctuations" and yield a more stable ASC and REP benefit calculation,[627] they do not suggest that the 3-year average is unreasonable or has led to anomalous results. Furthermore, given the IOUs' concerns about potential discrepancies between the Base Period's actual purchase power costs and the Exchange Period's forecast purchase power costs, using a larger average would appear to exacerbate these potential issues. BPA agrees with the IOUs' comment that using the 3-year average will make the price more "reactive" to short-term fluctuations, which is likely to be, all else equal, a better "predictor of future prices" than a 5-year average. [628]

Public Power customers also argue BPA is using a different logic between average calculation (3-year) and the utility spread calculation (5-year), creating an asymmetrical logic.[629] BPA agrees and has corrected this part of the ASCM. This was a typographical error in the draft 2026 ASCM. The correct value should have read 3-year in both places.

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[620] Public Power Comments (April) at 15.
[621] *Id.*
[622] *Id.*
[623] *Id.* at 16.
[624] *Id.*
[625] *Id.*
[626] *Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293, at 39,295 (Oct. 5, 1984).
[627] Public Power Comments (April) at 16.
[628] IOU Preliminary comment at 5.
[629] Public Power Comments (April) at 16.

Public Power customers argue that the 3-year average also "exacerbate[s] model sensitivity."[630] They contend that the REP model outputs are "notoriously sensitive to changes in inputs."[631] Public Power customers assert that the Rates Analysis Model (RAM) produces "wildly divergent results based on small changes to the inputs," indicating a need for greater stability. [632] To "quiet the interplay across variables" and achieve "stability in the ultimate rates themselves," they urge BPA to take steps to stabilize the model's inputs.[633] Therefore, Public Power customers advocate for using a "longer, five-year weighted average" instead of a three-year period for market-price forecasts in calculating Exchange Period ASCs.[634]

BPA recognizes that RAM is an integral part of the modeling for the PF and PF Exchange rate and for running the Section 7(b)(2) rate test. Minimizing fluctuations in inputs is a noble goal, but unless express statutory requirements are at issue, (such as in the context of transmission cost), those goals should not direct changes to the modeling used in ASCs. In any event, it is unlikely that calculating an ASC using a 3-year average of purchase power costs versus a 5-year average would cause the sort of "notorious" sensitivity Public Power customers identify. The 3-year average is a reasonable assumption, based on actual data, and provides a sensible approach to forecasting future prices.

As with the response to the IOUs, BPA notes that this issue may be moot if the alternative approach discussed next is adopted in the final ROD. BPA looks forward to Public Power's perspective on this alternative.

3. *__BPA Proposed Alternative for Stakeholder Consideration__*

As noted above, BPA views its current pricing method in the 2026 ASC Forecast Model as reasonable. Nevertheless, BPA offers an alternative method here for stakeholders to consider. BPA does not necessarily view this method as superior or having more merit. It addresses the same fundamental issue—bridging the gap between the Base Period and the Exchange Period—in a reasonable manner that BPA finds to be an appropriate alternative. Specifically, BPA proposes the following:

- Utility purchased power and Sales for Resale prices and quantities from the Base Period would be held constant into the Exchange Period.

- Incremental load growth from the Base Period into the Exchange Period would be priced at BPA's "Remarketing Value" typically known as a *firm power price* (*e.g.,* a forecast forward market price with considerations of capacity and physical delivery premiums) as used in several other areas of rate setting and established in each 7(i) Process.

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[630] *Id.*
[631] *Id.*
[632] *Id.*
[633] *Id.*
[634] *Id.*

- Load reductions from the Base Period (which would result in a surplus in the Exchange Period) would be priced at BPA's *average market price also known as the spot-market price* (*e.g.,* a forecast spot market price for energy) as used in several other areas of rate setting and established in each Section 7(i) Process.

This approach, which was shared with stakeholders at the July 31, 2026, workshop,[635] aims to reasonably address the concerns of the parties. First, regarding the IOU concerns, this method allows a utility to include costs or credits reported in the Base Period within its Exchange Period ASC. This mitigates the concern that a utility's actual purchased power or Sales for Resale is not fully accounted for in the Exchange Period ASC.

However, these historical costs and credits do not dictate the price for load growth (or additional surplus sales) made during the Exchange Period. Instead, for load growth/surplus sales projected to occur after the Base Period, BPA will use the same pricing it applies to similar sales in its own ratemaking. Specifically, BPA has historically used a "Remarketing Value" to calculate the cost of firm unpurchased inventory deficits as measured by its firm inventory planning standard (*e.g.,* BPA's P10 (10th percentile) firm monthly generation) and a forecast average *market price* to value its secondary sales – which are akin to a utility's Sales for Resale. This element of BPA's alternative links the pricing of the utility's ASC for the Exchange Period to a central source, ensuring that all of the utilities' ASCs (and BPA's PF Exchange rate) are adjusted by the same metric, and does not anchor it to past pricing (which may not be indicative of future prices).

BPA notes that this alternative approach changes utility's ASCs in different ways, with some increasing, and some decreasing. To help parties understand the impact of this proposal, BPA posted at the July 31, 2026 workshop a mock Appendix 1 with an ASC Forecast Model that uses this method.[636] BPA encourages stakeholders to review this model to see its functionality and provide BPA feedback on this proposal. Language implementing this proposal has also been added to the ASCM in redline as an alternative.

Draft Decision

The methodology for determining the price of power used for serving load growth and valuing Sales for Resale in the ASC Forecast Model is reasonable.

6.5 Major Resource Additions and Reductions and Materiality Thresholds (CFR § 301.5(c))

Starting with the 2008 ASCM, and in alignment with BPA's efforts to simplify ASC calculations, utilities can only update a limited number of areas from their Base Period information with new resource data. Section 301.5(c) of the 2026 ASCM details the specific criteria, thresholds, and requirements for utilities to update their Exchange Period ASCs with new resource information that becomes available after the Base Period.

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[635] ASCM Workshop 7, July 31, 2026, at 18.

[636] *See* Market Price Simplified Calculator, July 31, 2026, *available at* https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/market-price-simplified-calculator.xlsx.

6.5.1 Applicability of Within Rate Period Changes to ASC (CFR § 301.5(c)(1))

The 2026 ASCM allows adjustments to a utility's ASC during the Exchange Period for significant resource changes. However, these adjustments are contingent upon meeting the criteria in § 301.5(c)(3) and the materiality threshold in paragraph (c)(4). The impact of these major resource additions or reductions on a utility's Exchange Period ASC is determined exclusively during the ASC review process. This means that only major resource changes that are known, forecasted, and addressed within the ASC review process and included in the utility's ASC Report will be accounted for. The ASC Report reflects these new resources by calculating an adjusted Exchange Period ASC. New resource additions or reductions not forecasted during the ASC Report will not lead to a change in a utility's ASC.

Under the 2012 REP Settlement and its implementing agreement (REPSIA), utilities could waive their right to update their ASC during the Exchange Period with new resource information. Historically, if a utility agreed not to modify its ASC for new resources during the Exchange Period, BPA would similarly agree not to change the utility's PF Exchange rate during that period due to rate adjustments like surcharges or cost-recovery clauses. Recognizing these reciprocal agreements, the 2026 ASCM acknowledges that a utility's right to seek ASC adjustments for new resources might be limited by the terms of the contract implementing the REP, specifically the Residential Purchase and Sale Agreement (RPSA).

6.5.2 Effective Date of Change (CFR § 301.5(c)(2))

Section 301.5(c)(2) explains the timing of ASC changes associated with new resource additions or reductions.

6.5.3 Major Resource Addition or Reduction Categories (CFR § 301.5(c)(3))

Section 301.5(c)(3) describes the general categories of resource costs that can trigger an adjustment to an ASC.

6.5.4 Materiality Threshold (CFR § 301.5(c)(4))

Before a utility's ASC is adjusted to reflect the addition or loss of a major resource, the utility must demonstrate that the proposed resource will meet the materiality requirements set forth in the 2026 ASCM. Section 301.5(c) of the 2026 ASCM sets forth the materiality requirements. As explained in *Issue 6.5.7*, BPA inadvertently omitted language in the 2026 ASCM that would have permitted utilities to aggregate individual resources to meet the 2.5 percent threshold. BPA has returned that language to the 2026 ASCM.

6.5.5 Major Resource Addition or Reduction Calculation (CFR § 301.5(c)(5)-(12))

Sections 301.5(c)(5)-(12) provide additional information about how new resources that meet the materiality threshold will be treated. In general, when a utility submits its Appendix 1 filing, it must forecast all major resource additions or reductions and associated costs from the end of the Base Period through the Exchange Period. BPA reviews these forecasts as part of the ASC review process. All major resources included in initial ASC calculations are projected to the midpoint of the Exchange Period. For any forecasted major resource changes during the Exchange Period, BPA calculates the difference in ASC (ASC delta) between scenarios with and without the change. Once a major resource change becomes effective, this ASC delta is added to the utility's existing ASC to determine the new Exchange Period ASC. BPA also escalates the components of resource costs for new large single loads (NLSLs) to the Exchange Period, ensuring fully allocated costs are adjusted and that the Exchange Period NLSL load matches the Base Period. Furthermore, BPA escalates the average per-MWh cost of Distribution Plant and the cost of General Plant (Accounts 389-399.1) to the midpoint of the Exchange Period to determine distribution-related costs for load growth and to calculate adjusted General Plant values, respectively.

For major resource additions to be included in a utility's Exchange Period ASC at the beginning of the Exchange Period, a Major Resource Attestation must be received by BPA.

6.5.6 Confidentiality for Major Resource Additions or Reductions (CFR § 301.5(c)(13))

Because including new resource information often involves commercially sensitive data for many utilities, the ASCM includes specific procedures to maintain confidentiality during the ASC review processes. Section 301.5(c)(13) assures utilities that these procedures are in place to protect their confidential information related to new resources, in accordance with the ASC Confidentiality Rules.

6.5.7 Issues

<u>Issue 6.5.7.1</u>

Whether BPA should adjust the materiality thresholds in the draft 2026 ASCM by either removing the lower materiality threshold of 0.5 percent or prohibiting any changes for new resources during the Exchange Period.

<u>BPA Staff's Proposal</u>

The 2026 ASCM allows utilities to reflect in their Exchange Period ASCs major resource additions or reductions that occur between the Base Period and Exchange Period if such resources meet a materiality threshold of 0.5 percent or greater in the utility's Base Period ASC.[637] This is a change from the 2008 ASCM, which set the materiality threshold at 2.5 percent.

For major resource additions or reductions that occur during the Exchange Period, the 2026 ASCM retains the 2008 ASCM materiality threshold of 2.5 percent.[638]

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[637] *See* 2026 ASCM § 301.5(c)(4).
[638] *Id.*

Parties' Positions

Public Power customers oppose BPA's proposed adjustments to the ASCM for new resources, particularly the 0.5 percent materiality threshold, arguing that the current Base Period framework already sufficiently addresses differences between the Base Period and Exchange Period.[639] They contend that lowering this threshold needlessly destabilizes the ASC and urge BPA to maintain the existing thresholds.[640]

For the Exchange Period, Public Power customers argue that ASC adjustments should align with RPSA authorizations, rejecting a grouped materiality approach in favor of a 2.5 percent per-resource threshold, mirroring current service territory change standards to preserve the Base Period ASC's integrity and ensure adjustments are only for significant changes.[641]

AWEC opposes BPA's inclusion of any changes from the Base Period ASC to the Exchange Period ASC because of new resource additions. AWEC argues that reflecting these new resource costs in ASC introduces "unwarranted volatility" and "undermine[s] predictability and administrative efficiency . . . ."[642]

Evaluation of Positions

1. Background of the Materiality Threshold in the 2008 ASCM

As discussed in section 3.3.2.1.2 of this ROD, a utility's ability to modify its ASC for new resource additions or reductions occurring after the Base Period is restricted. The 2008 ASCM specifically addresses changes to a utility's ASC that may occur during the Exchange Period.[643] If a utility anticipates the addition of new resources, the loss of resources, or a loss or gain in territory that occurs in the Exchange Period, it may forecast these changes during the ASC review process.[644] BPA Staff will calculate an ASC based on these changed resources or territory and include a revised ASC in the utility's ASC report. When the anticipated resources or territory changes occur during the Exchange Period, the utility informs BPA and provides proof that the new resource is operating or that the change in territory has taken place.[645] If BPA is able to confirm the resource or territory change, then the utility's Exchange Period ASC is updated to reflect the new resource costs.

Not every resource addition or change is permitted to affect the utility's ASC. For a resource or territory change to affect a utility's ASC during the Exchange Period, it must pass a materiality threshold: the total impact from a resource or territory change must affect the utility's Base Period ASC by at least 2.5 percent.[646] A utility may combine

639 Public Power Comments (April) at 9.
640 *Id.*
641 *Id.*
642 AWEC Comments (April) at 8.
643 18 C.F.R. § 301.4(c)(1)("During the Exchange Period, Bonneville will allow changes to a Utility's ASC to account for major re-source additions or reductions that are used to meet a Utility's retail load.")
644 *Id.; see also id.* § 301.4(f) (changes to service territory).
645 *Id.* § 301.4(c)(2).
646 *Id.* § 301.4(c)(4).

multiple smaller resource changes to meet this materiality threshold, but each individual resource change must impact the utility's Base Period ASC by at least 0.5 percent.[647]

The 2008 ASCM did not specifically address changes to a utility's ASC that occur after the Base Period but before the Exchange Period. The period between the Base Period and the commencement of the Exchange Period is colloquially known as the "twilight period." For example, in the FY 2026 ASC review process, the Base Period ASC was based on calendar year information from 2023. The FY 2026 ASC Review Process commenced on July 1, 2024, and concluded on July 24, 2025. The Exchange Period started on October 1, 2025, and continues through September 30, 2028. In this specific example, the "twilight period" would span from January 1, 2024, through July 24, 2025.

If a new resource came online during the "twilight period," BPA as a matter of practice would allow the utility to reflect that resource in its Exchange Period ASC if it met the same materiality threshold discussed above. That is, BPA would adjust the utility's Exchange Period ASC if the impact on the Base Period ASC was 2.5 percent or greater. If the new resource's impact was below this threshold, it would not be counted immediately; instead, those costs would eventually be incorporated into the utility's ASC in a future Base Period. BPA also permitted utilities to aggregate smaller resources to meet the 2.5 percent materiality threshold. In such instances, each smaller resource individually had to impact the utility's Base Period ASC by at least 0.5 percent. Thus, a utility could combine five small new resources, each with a 0.5 percent impact on the utility's ASC, to achieve the 2.5 percent major resource materiality threshold. In that scenario, once all the small resources became operational, their combined impact would be applied to the utility's Exchange Period ASC. Importantly, changes to an ASC during the "twilight period" would occur only if the resource actually comes online during this specific timeframe. Before the commencement of the Exchange Period, the utility must provide proof that the new resources have become operational.

2. *<u>2026 ASCM Materiality Threshold</u>*

For the 2026 ASCM, BPA proposes to formally incorporate the "twilight period" treatment for new resource additions or reductions.[648] Furthermore, for resource changes occurring during this "twilight period," BPA proposed removing the 2.5 percent materiality threshold, which was originally designed to address changes to ASCs *during* the Exchange Period, not before it. Instead, the utility's ASC would reflect any new resource addition or reduction that meets a smaller, 0.5 percent minimum threshold. BPA put forward this change in response to feedback from IOUs and because the administrative burden and uncertainty associated with this approach were deemed minimal.[649] However, BPA intends to keep the 2008 ASCM materiality requirements for changes to an Exchange Period ASC that happen during the Exchange Period.[650] This means the 2.5 percent threshold will still apply to update an Exchange Period ASC with new resource additions or reductions that occur

[647] *Id.*
[648] *See* 2026 ASCM § 301.5(c)(4).
[649] *See* IOU Comments on Preliminary ASCM Draft, Jan. 21, 2026, at 7.
[650] *See* 2026 ASCM § 301.5(c)(4).

during the Exchange Period. Utilities will be permitted to aggregate smaller resources to meet this threshold, provided each individual resource results in at least a 0.5 percent impact.

During its review of the 2026 February Draft ASCM, BPA discovered an error in § 301.5(c)(4) regarding the materiality requirements. While revising the text to allow for "twilight period" adjustments, BPA unintentionally removed the provision that enabled utilities to combine small resources to meet the 2.5 percent materiality threshold for adjustments during the Exchange Period. Each of these smaller resources needed to meet a 0.5 percent materiality threshold to be aggregated to reach the 2.5 percent threshold. BPA did not intend to remove this provision and has since reinstated it in § 301.5(c)(4) of the 2026 ASCM.

3. <u>Public Power Customers and AWEC's Comments Regarding the Materiality Thresholds</u>

a. Changes to ASC during the Twilight Period

Public Power customers oppose BPA's proposed treatment of new resource additions or reductions in the ASC, including the 0.5 percent materiality threshold.[651] The Public Power customers argue that the existing ASC framework, which relies on a Base Period cost structure and escalation factors, already addresses differences between forecasted and actual load-resource balances.[652] Public Power customers argue that lowering the threshold to 0.5 percent unnecessarily undermines the stability and predictability intended by the Base Period ASC construct.[653] Therefore, Public Power customers urge BPA to not change its thresholds.[654] AWEC also argues that allowing more new resource costs into ASC, at a lower threshold, and without removing disallowed cost, is "doubly concerning" and should be avoided.[655]

BPA disagrees with the claim that codifying the "twilight period" ASC adjustments and permitting resources meeting the 0.5 percent threshold to modify a utility's Exchange Period ASC is unreasonable, unstable, or unpredictable. BPA's proposal to allow new resource costs into a utility ASC during the twilight period simply means the utility's ASC is being updated for actual, operating resources. Therefore, BPA is not suggesting an ASC change based on future resource predictions. Resources allowed during the twilight period are already online, supplying power to meet the utility's load, or are slated to come online shortly during the ASC review process. These resources unequivocally represent a cost of a utility's resources during the Exchange Period.

Additionally, Public Power customers' concerns that this approach will create instability in other components of the REP, such as ratemaking or the PF Exchange rate, is incorrect. BPA has, in effect, used a proposal similar to this approach under the 2008 ASCM and seen no disruption through the ASC review processes. BPA's experience is that including these

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[651] Public Power Comments (April) at 9.
[652] *Id.*
[653] *Id.*
[654] *Id.*
[655] AWEC Comments (April) at 8.

resources in the Exchange Period ASC will not create instability or disconnects with rate case forecasts. New resources incorporated during the ASC review process will be part of the utility's Exchange Period ASC in the final ASC Report, which will then be used in ratemaking and the PF Exchange rate formation.

The administrative burden of allowing these resources into ASC is also minimal. BPA is maintaining the 0.5 percent minimum requirement, ensuring that only resources with a noticeable impact on the Base Period ASC are considered, while smaller, insignificant resources are excluded. Thus, BPA's approach allows utilities to include impactful resources while still applying a reasonable limit. In fact, this approach should reduce the administrative burden for both BPA and the utility. Previously, BPA had to work with utilities as they tried to combine multiple resources to meet the 2.5 percent threshold. Sometimes, utilities incorrectly combined resources or missed the threshold by a small margin, such as 0.01 percent.[656] A stringent requirement like that might be sensible for changes during the Exchange Period when the altered ASC deviates from the one used in rate case forecasting. However, for the "twilight period," the adjusted ASC becomes the Exchange Period ASC used in ratemaking, eliminating any difference. Therefore, the policy reasons to maintain a higher percentage threshold do not apply to resource adjustments made during the "twilight period."

b. Changes to ASC during the Exchange Period

Both Public Power customers and AWEC raise concerns with BPA's proposal to allow changes to ASC during the Exchange Period. For the Exchange Period, Public Power customers argue that any ASC adjustments should only occur as authorized by the RPSA.[657] In particular, Public Power customers argue that BPA should not use a grouped materiality approach for resource-related adjustments; instead, they advocate for a 2.5 percent materiality threshold applied on a per-resource basis, consistent with existing standards for service territory changes.[658] Public Power customers contend this method maintains the integrity of the Base Period ASC, aligns with current materiality standards, and ensures that Exchange Period adjustments are only made for truly significant changes.[659]

AWEC opposes BPA including *any* changes from the Base Period ASC to the Exchange Period ASC because of new resource additions.[660] AWEC argues reflecting these new resource costs in ASC introduces "unwarranted volatility" and "undermine[s] predictability and administrative efficiency . . . ."[661] AWEC also claims it is "one-sided."[662] AWEC's

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[656] *See e.g.,* Idaho Power FY 2026-2028 Final ASC Report, at 12 (July 24, 2025) (on file with author) (noting Idaho Power's grouped resources did not meet the 2.5 percent minimum threshold because one of five resources was under the 0.5 minimum percent).
[657] Public Power Comments (April) at 9.
[658] *Id.*
[659] *Id.* at 9-10.
[660] AWEC Comments (April) at 8.
[661] *Id.*
[662] *Id.*

concern is that this approach allows for the inclusion of resource costs outside of the Base Period, without updating other Base Period inputs.[663]

BPA disagrees that its proposal to allow material changes to a utility's ASC during the Exchange Period is unreasonable or otherwise improper. First, in response to Public Power customers' concerns that changes during the Exchange Period should be limited by the RPSA, BPA notes that the 2026 ASCM covers these situations. Section 301.5(c)(1) begins with this statement: "*Unless otherwise limited under the Residential Purchase and Sale Agreement between Bonneville and the Utility*, during the Exchange Period, Bonneville will allow changes to a Utility's ASC to account for major resource additions or reductions that are used to meet a Utility's retail load." The italicized language ensures that any contractual restrictions in the RPSA on a utility's ability to change its ASC would control over the ASCM's terms.

Second, BPA believes the current ASCM effectively balances the need to update a utility's ASC with new resource or territory information, without leading to a continuous review process. Under the 2026 ASCM, a utility's Exchange Period ASC can only be adjusted if three conditions are met: (1) the new resource/territory was *forecasted* in the ASC review process; (2) the new resource or change in territory increases the utility's Base Period ASC by at least 2.5%, which can include aggregated individual resources of at least 0.5%; and (3) the new resource/territory change must actually occur. If any of these conditions are not met, the new resource or territory change will not be incorporated into the utility's ASC. This stringent set of criteria ensures that any modifications to a utility's ASC are both significant and verified, preventing arbitrary or frequent adjustments.

Third, BPA disagrees with the argument from Public Power customers and AWEC that the requirements for material changes should be heightened (*e.g.,* by increasing the threshold for all resources to 2.5 percent) or that all changes should be eliminated. BPA maintains that allowing limited adjustments to the Exchange Period ASC is reasonable.

It is important to understand that allowing limited changes to an ASC during the Exchange Period was a significant shift from the previous approach under the 1981 and 1984 ASCMs. Before the 2008 ASCM, a utility's ASC changed whenever it sought a new retail rate adjustment.[664] This resulted in utilities constantly altering their ASCs during the Exchange Period, with BPA sometimes reviewing up to 20 such filings at once.[665] Beyond the administrative complexities this approach introduced, a major issue was the discrepancy between the ASCs used for forecasting the costs of the REP for rates and the ASCs upon which BPA actually paid REP benefits. Because there was no required link between the ASCs used in ratemaking and those used in actual REP payments, there were often differences between the anticipated and actual REP benefits. These discrepancies undermined protections, such as those required under Section 7(b)(2), due to inherent differences between forecast and actual ASCs.

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[663] *Id.*
[664] 2008 ASCM ROD at 8.
[665] *Id.* at 6.

The 2008 ASCM largely resolved these issues. BPA redesigned the ASCM to align ASC review processes with BPA's rate cases, set the Exchange Period to span the entire rate period, and permitted only limited, material adjustments to the Exchange Period ASC. This move away from constantly changing and disconnected ASCs (based on forecasts versus actuals) was acceptable to regional IOUs and state commissions because it still allowed for adjustments when they were significant.[666]

BPA believes that the approach adopted in the 2008 ASCM achieved the right balance; it avoided the constant ASC changes seen when utilities made retail rate filings, while also preventing a situation where utilities could not adjust their ASCs for changes they knew were coming during the ASC review process. BPA finds that the reasons presented by AWEC or Public Power customers do not indicate that this carefully constructed approach from the 2008 ASCM has become unbalanced or requires revision in the 2026 ASCM.

Draft Decision

BPA will retain the materiality thresholds in the draft 2026 ASCM as proposed (with the return of omitted language). BPA will not remove the lower materiality threshold of 0.5 percent nor prohibit changes for new resources during the Exchange Period.

6.6 Forecasting Contract System Load and Exchange Load (CFR § 301.5(d))

For Forecast Contract System Load and Exchange Load definitions *see* § 301.2 Definitions.

As part of its ASC Filing, each IOU is required to provide a fiscal year forecast of its total retail load, as measured at the meter. Additionally, residential and farm load forecasts are provided.

Each utility is required to submit a distribution loss calculation as described in the 2026 ASCM. The total retail and the residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate). The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

6.7 Load Growth Not Met by Major Resources (CFR § 301.5(e))

All load growth not met by new resource additions is met by purchased power at the applicable short-term purchased power price. To calculate the cost of serving load growth not served by new resource additions, BPA uses the method outlined in the 2026 ASCM.

See section 6.4 of this ROD for details regarding the power purchase and sales mechanism used in the 2026 ASC Forecast Model.

6.8 Changes to Service Territory (CFR § 301.5(f))

Section 301.5(f) addresses the situation where a utility anticipates a change in its service territory that will alter its Base Period ASC by 2.5 percent or more. In such case, the utility must submit two Appendix 1 filings to BPA. The first filing will reflect the Base Period ASC

[666] *Id.* at 47.

without the territory change, while the second will incorporate comprehensive forecasts of how the acquisition or loss of territory impacts Contract System Load, Contract System Cost, capital and operating expenses, and purchased power and sales for resale. BPA will only adjust the utility's ASC once the service territory change has actually occurred, not based on forecasted dates.

BPA modified the language in § 301.5(f) to clarify that the utility must file alternative Appendix 1s (rather than its Base Period ASCs). BPA explained this change at its July 31, 2026, workshop.[667]

6.9 Changes to Service Territory and Formation of New Utilities After the Exchange Period Starts (CFR § 301.5(g))

Section 301.5(g) was revised to address a new set of issues associated with utility service territory changes occurring after the Exchange Period commences. The original text of § 301.5(g) contained certain filing requirements for utilities with service territory changes. This language was moved to the filing requirement section of the ASCM (§ 301.3(c)).[668] Instead, BPA added new language to § 301.5(g) to address the unique situation where a new utility is created out of an existing REP-participant's territory after the filing of the Appendix 1s but before the end of the Exchange Period. It also addresses the situation whenever a utility otherwise eligible to participate in the REP does not have a FERC Form 1 with a full year's worth of data from which to calculate a Base Period ASC.

Section 301.5(g) addresses four scenarios. First is the situation where a new utility is formed from an existing REP-participating utility. In that instance, § 301.5(g)(i) provides the new utility will assume the ASC of the prior utility until the new utility has a "full-year FERC Form 1 for the Base Period."[669] Second is the situation where a new utility is formed from one or more REP-participating utilities. For that case, the new utility's ASC will be the prior utilities' ASCs "weighted by the percentage of each service territory assumed from the respective Utilities . . ."[670] Once again, this ASC will remain in effect for the new utility "until the newly-formed Utility has a full-year FERC Form 1 for the Base Period."[671] In both of these situations, BPA's intent with the 2026 ASCM is to continue REP payments to retail consumers who were previously eligible to receive them. The creation of a new utility should not pause or otherwise disrupt the flow of REP payments to the end-use consumer (provided the new utility is properly formed and executes appropriate contracts for REP participation).

The third scenario involves a new utility formed from an existing Public Power Entity or another entity that is not currently receiving REP payments (and has not executed an RPSA).[672] In this case, the new utility receives an ASC equal to BPA's PF Exchange rate,

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[667] ASCM Workshop 7, at 20, July 31, 2026.
[668] *See* section 4.3 of this ROD.
[669] 2026 ASCM § 301.5(g)(i).
[670] *Id.* § 301.5(g)(ii).
[671] *Id.*
[672] *Id.* § 301.5(g)(iii).

effectively pausing its participation until it establishes an ASC under the 2026 ASCM. Because no existing ASC applies to its consumers, and they are not currently receiving REP benefits, the utility must wait until the next ASC review cycle to fully participate in the REP.

The final scenario covered by § 301.5(g) is the situation where a utility participating in the REP transfers some or all of its territory to a Public Power Entity that has not executed an RPSA. In that situation, no ASC will be established for the Public Power Entity for the load transferred to it. Because the Public Power Entity has not executed an RPSA, the REP payments for such load will end.[673]

BPA discussed these changes at its July 31, 2026 workshop.[674] The IOUs filed interim feedback comments supporting these adjustments.[675]

[673] *Id.* § 301.5(g)(iv).
[674] *See* ASCM Workshop 7, at 21, July 31, 2026.
[675] IOU Interim Feedback on July 31 Workshop, Aug. 14, 2026, at 8.

7.0 CHANGES IN AVERAGE SYSTEM COST METHODOLOGY (CFR § 301.6)

7.1 Changes to the ASCM (CFR § 301.6(a)-(b))

Sections 301.6(a)-(b) state that the BPA Administrator has the discretion to initiate a consultation process, as outlined in Section 5(c) of the Northwest Power Act, after which the Administrator may file a new ASC Methodology with the Commission. This section further notes that the consultation process will not begin until at least one year of experience has been gained under the existing ASC Methodology, following its adoption by BPA and interim or final approval by the Commission.

7.2 Interpretations and FERC Account Adjustments to the ASCM (CFR § 301.6(c)-(d))

Section 301.6(c) allows BPA to issue interpretations of the ASCM as needed, typically when identifying overarching issues that affect multiple utility ASCs. This section also addresses potential changes to the functionalization code of any FERC account within the 2026 ASCM. Such changes might be necessary to exclude statutorily prohibited costs or to align the FERC account's cost treatment with the requirements of the 2026 ASCM.

Section 301.6(d) addresses how BPA will handle changes to FERC accounts by the Commission. It allows BPA to adapt the 2026 ASCM to these modifications by updating functionalization codes or escalation rules as necessary. BPA added clarifying language to this section to ensure the ASCM is adaptable to changes made by FERC to its account system. BPA discussed these changes at the April 15, 2026, workshop.[676]

7.3 Issues

<u>Issue 7.3.1</u>
Whether BPA should revise the terms for requesting a new consultation under the ASCM.

<u>BPA Staff's Proposal</u>

The 2026 ASCM revised and reorganized 18 C.F.R § 301.5(a) to remove the discretionary right for three-quarters of a sub-group of BPA customers to request the Administrator to commence a consultation process for a new ASCM.

<u>Parties' Positions</u>

The Public Power customers assert that their customer groups have historically relied on the Section 5(c)(7) consultation process to address previous ASCM deficiencies.[677] They express significant concern over BPA's proposal to eliminate customer-initiated consultations, viewing it as removing a vital mechanism for identifying and correcting flaws in the 2026 ASCM.[678] Given their customers' substantial financial stake in the REP

[676] ASCM Workshop 6, at 16, April 15, 2026.
[677] Public Power Comments (April) at 10.
[678] *Id.*

rate subsidy, the Public Power customers contend that retaining the ability to trigger these consultations is crucial for ratepayer protection and Act compliance.[679]

Evaluation of Positions

BPA has considered Public Power customers' comment on this issue and agrees to retain the language from the 2008 ASCM in the 2026 ASCM with one modification. The language BPA intends to include is as follows:

> The Administrator, at his or her discretion, or upon written request from three-quarters of the utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of Bonneville's preference customers, may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, Bonneville's Administrator may file the new ASC methodology with the Commission.[680]

BPA has only made one change to this language: removing the reference to direct service industry customers, as only a single direct service industry (DSI) customer remains. BPA's initial concern was that customers might request such proceedings when BPA's resources were already strained by other matters. However, as the original language clarifies, a request from three-quarters of a customer group does not obligate BPA to commence the consultation process. The language maintains the Administrator's discretion in deciding whether to initiate a consultation. This phrasing was present in both the 2008 and 1984 ASCMs.[681] With the exception of removing the reference to the DSIs, BPA will retain this language.

Draft Decision

BPA will retain the terms of the 2008 ASCM in the 2026 ASCM for requesting a new consultation under the ASCM, except for removing the reference to the direct service industries.

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[679] *Id*.
[680] 18 C.F.R. § 301.5(a).
[681] *See* 2008 ASCM ROD, Attachment A, at 13-14; *See* 1984 ASCM ROD, Attachment, 1984 ASCM at 7.

8.0 PROVISIONS FOR PUBLIC POWER CUSTOMERS (CFR § 301.7)

Section 5(c) of the Northwest Power Act permits any utility in the region to participate in the exchange, including public power customers.[682] As such, since passage of the Northwest Power Act, public power utilities have participated in the REP.[683] In order to preserve the value of the low-cost federal power system, public power customers agreed to a partial waiver of their rights to participate in the REP under the Regional Dialogue contracts, which operated from 2011 to 2028.[684] To accommodate this partial waiver, the 2008 ASCM included special provisions for participating public customers with Regional Dialogue contracts.[685]

In the Provider of Choice Policy, BPA expanded the limited REP waiver applicable to Public Power customers. 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."[686] All Public Power customers have since signed Provider of Choice contracts and accepted the waiver of their rights to participate in the REP from October 1, 2028 through September 30, 2044. In view of this waiver, BPA has removed the special terms relating to the Regional Dialogue partial waiver from the 2026 ASCM. To the extent Public Power customers return to participating in the REP, § 301.7 of the ASCM makes clear that such participation will be subject to "the ASCM provisions applicable as REP-participating IOUs and provide data equivalent to FERC Form 1." This provision ensures that Public Power utilities that request an ASC are placed in no better or worse position than a corresponding IOU for the purpose of complying with the terms of the 2026 ASCM.

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682 16 U.S.C. § 839c(c)(1) ("Whenever a Pacific Northwest electric utility offers . . .")
683 *See* 2026 RPSA ROD at 58, fn 407 (noting that 112 Public Power customers participated in the REP initially).
684 *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.
685 *See* 18 C.F.R. § 301.4(g).
686 POC Policy at § 10.1.

9.0 FUNCTIONALIZATION, ESCALATION CODES, AND ENDNOTES (TABLE 1)

9.1 Overview

Table 1 is a key component of the 2026 ASCM. It connects the methodology with the account-level data used in Appendix 1 and the 2026 ASC Forecast Model, with exceptions for data sourced elsewhere. Table 1 describes functionalization and escalation codes. Functionalization codes in Appendix 1 and the 2026 ASC Forecast Model determine the business function (Production, Transmission, Distribution/Other) to which costs are assigned. Escalation codes are used to forecast costs from the Base Period through the Exchange Period.

9.2 Functionalization and Escalation Codes (Table 1)

Table 1 contains Functionalization and Escalation codes assigned to individual accounts, as well as ranges of accounts, as described in the first column. Table 1 prescribes how codes will be ultimately assigned in the Appendix 1 and 2026 ASC Forecast Model.

Functionalization codes are used to assign utility costs to three possible functions: Production, Transmission, and Distribution/Other. Distribution/Other is assigned to amounts that are either directly attributable to Distribution or otherwise omitted from a utility's ASC.

Each account in the Appendix 1 is assigned a default Functionalization code. Additionally, some accounts are assigned an optional code, whereby the participating utility may utilize an alternative method of functionalization. However, once a utility uses a specific functionalization method for an account, the utility may not change the functionalization method for that account without prior approval from BPA.[687]

Following BPA's publication of the February 2026 ASCM for draft comment, BPA identified a number of updates to Table 1. These updates were needed to reflect recent changes to the names, code numbers, and break-out of certain FERC accounts. BPA presented these changes at the April 15, 2026 workshop.[688]

9.3 Endnotes (Table 1)

The 2026 ASCM has added a set of endnotes to Table 1. Endnote letter references are found throughout Table 1. The body of endnotes immediately follows Table 1 in the 2026 ASCM. This is a structural change from the 2008 ASCM. The 2008 ASCM had a section labeled *IX, Average System Cost Methodology Appendix 1 Endnotes*. By incorporating the relevant substantive material from that section directly into the main text, the 2026 ASCM reduces the endnotes to text references attached directly to Table 1, rather than retaining a separate section.

[687] 2026 ASCM § 301.4(l)(1).
[688] ASCM Workshop 6, April 15, 2026.

10.0 AVERAGE SYSTEM COST METHODOLOGY TEMPLATES AND MODELS (APPENDIX 1 AND FORECAST MODEL)

10.1 ASCM Appendix 1

Appendix 1 is the primary source of data used in the ASC Forecast Model to determine each participating utility's Exchange Period ASC. It is comprised of a series of interconnected tabs within a spreadsheet. BPA prepares the Appendix 1 Template and provides it to exchanging utilities.

10.2 ASC Forecast Model

The 2026 ASC Forecast Model is an Excel-based model that applies the Escalation codes and other adjustments called for in the 2026 ASCM to the Base Period ASC to establish the Exchange Period ASC. Table 1 identifies the Escalation codes for each applicable account used in the 2026 ASC Forecast Model. *See* Section 6 of this ROD for additional explanation of the Exchange Period ASC and 2026 ASC Forecast Model.

11.0 AVERAGE SYSTEM COST REVIEW PROCEDURES (ASCM PART II: ASC PROCEDURES)

11.1 Overview

BPA's ASC Procedures establish the filing procedures, deadlines, and requirements for utilities to compile their Appendix 1 filings and participate in the ASC review processes. As noted above, the ASC Procedures are BPA rules and, although part of the 2026 ASCM, are not filed with FERC.

11.2 Filing Procedures (ASC Procedures § 2)

Section 2 of the ASC Procedures provides the requirements for utilities to compile and submit a complete Appendix 1 filing to BPA. The Appendix 1 filing will establish the utilities' Base Period ASCs.

11.3 ASC Review Process (ASC Procedures § 3)

Section 3 of the ASC Procedures establishes the procedures for evaluating ASCs. Included in this section are details on the requirements for intervening and participating in the ASC review process. Parties intending to review Confidential Information must also submit a Confidentiality Agreement.

These rules also make it clear that BPA independently assesses the appropriateness and reasonableness of costs included in Contract System Cost and the loads included in the Contract System Load. The process also includes a discovery phase in which BPA and participating entities electronically file data requests. Utilities must respond within ten calendar days or face the potential removal of associated costs if the requested data is not provided. Clarification workshops may be held, BPA and participating parties may file issue lists, and BPA may grant an opportunity to present oral arguments at its discretion. Finally, the process concludes with Draft ASC Reports for comment and subsequent Final ASC Reports issued by BPA.

11.4 ASC Review Schedule (ASC Procedures § 4)

Section 4 retains the ASC review process from the 2008 ASCM and lays out a schedule of events.

11.5 Retail Rate Proceeding Data (ASC Procedures § 5)

Section 5 describes BPA's ability to petition to intervene in utilities' jurisdictional rate case filings for the purpose of obtaining information relevant to determining ASCs.

11.6 Senior Financial Officer Attestation and Confidentiality Rules (ASC Procedures Attachments A & B)

Utilities are required to include a signed Senior Financial Officer Attestation in their ASC filings (Attachment A). In addition, consistent with Section 3, parties seeking access to confidential information must submit the Confidentiality Agreement required by BPA's ASC Confidentiality Rules (Attachment B).

11.7 Issues

<u>Issue 11.7.1</u>

Whether BPA should provide additional transparency in the commencement of an ASC review process.

<u>BPA Staff's Proposal</u>

Section 2.3.2 of BPA's ASC Procedures provides that BPA "shall provide public notice of the right to file a petition to intervene in BPA's ASC Review Process."

<u>Parties' Positions</u>

AWEC requests that BPA provide additional transparency in the commencement of an ASC review process by initiating an ASC public workshop at least two weeks before the ASC review process begins.[689]

<u>Evaluation of Positions</u>

ASC review processes are quasi-administrative proceedings in which BPA determines a utility's ASC pursuant to the terms of the ASCM. Participants in these proceedings may request data and explanations from participating utilities on matters relevant to their ASC. Because of these procedural rights, the ASC Procedures require stakeholders to formally intervene in these proceedings in order to participate.[690]

In the 2026 ASCM, BPA agreed to provide more transparency around the commencement of the ASC review process. Upon the commencement of an ASC review process, BPA committed to "provide public notice of the right to file a petition to intervene in BPA's ASC Review Process."[691]

AWEC requests additional transparency in the commencement of an ASC Review Process through a public notice of a workshop at least two weeks before the review process begins.[692] AWEC understands the need for formal communications with BPA to participate in the ASC process, but believes an informal workshop prior to a formal process would "ensure that interested stakeholders are notified and able to efficiently participate, if desired."[693]

BPA understands stakeholders' desire for additional information regarding a proceeding before committing scarce resources to intervening and formally engaging in it. To that end, BPA agrees that if an informal workshop is appropriate prior to the commencement of a formal ASC review process, BPA will hold one. However, BPA does not believe it is prudent

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[689] AWEC Comments (April) at 9.
[690] *See* 2026 ASCM, ASC Procedures, § 3.1.
[691] *See* 2026 ASCM, ASC Procedures, § 2.3.2.
[692] AWEC Comments (April) at 9.
[693] *Id.*

to codify a requirement in the ASC Procedures to hold a workshop prior to every formal ASC review. Beyond informing regional parties that the ASC review process is about to commence, BPA is unclear as to what the specific subject matter of such a workshop would be. No ASC information would be available at the workshop, as the participating utilities would not file their ASCs until the formal ASC review process commences. Thus, while BPA may hold informal ASC workshops as needed prior to the commencement of the formal ASC review process, BPA finds that the public notice required by § 2.3.2 of the ASC Procedures should suffice in most instances.

Draft Decision

BPA may hold informal workshops prior to the commencement of an ASC review process, as appropriate.

Issue 11.7.2
Whether BPA should expand the scope and impact of the variance analysis in the ASC Procedures.

BPA Staff's Proposal

In Part II of the 2026 ASCM, under the ASC Procedures, BPA added a "variance analysis" requirement to utility filings.[694] This analysis requires a utility to compare certain components of its current ASC with data from its prior Base Period ASC filing's final Appendix 1 inputs.[695]

Parties' Positions

Public Power customers recommend that BPA require a variance analysis for all Appendix 1 inputs, similar to how utility regulators use this tool for FERC accounts.[696] They argue that this would significantly support BPA's ASC determinations.[697] While BPA's proposed rules include a variance analysis, Public Power customers suggest a broader historical scope, specifically covering two prior Base Periods and two prior informational ASC filings.[698] Public Power customers also argue that BPA should reserve the right to normalize inputs that lack adequate justification for major deviations.[699]

AWEC makes similar points in its comments.[700]

Evaluation of Positions

In the 2008 ASCM, there was no requirement for a utility to include a variance analysis in its ASC filing. Instead, BPA Staff performed this analysis when considering whether a particular FERC account included anomalous costs. In the 2026 ASCM, BPA proposes to incorporate a variance analysis requirement to efficiently identify significant discrepancies

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[694] 2026 ASCM, ASC Procedures, § 2.1.1.1(d).
[695] *Id.*
[696] Public Power Comments (April) at 11.
[697] *Id.*
[698] *Id.* at 12.
[699] *Id.*
[700] AWEC Comments (April) at 8.

from previous Base Period ASC filings. This low-burden yet high-yield approach will enable BPA Staff to quickly pinpoint accounts that warrant additional review.

Both Public Power customers and AWEC argue that BPA should expand the scope and impact of the variance analysis.[701] They propose that BPA require utilities to include the past four years of data in this analysis and expand the number of accounts subject to it. Furthermore, these parties argue that BPA should maintain the authority to "normalize" account information if there is insufficient justification for significant deviations.[702]

BPA disagrees that these additional requirements are reasonable or should be added to its ASC Procedures. The variance analysis is designed to help BPA Staff identify FERC accounts that warrant further attention. In BPA's experience, this can be achieved by comparing the limited set of schedules identified in the ASC Procedures from one Base Period to the same set from a previous Base Period's final Appendix 1. Adding more years or accounts, as suggested by Public Power customers and AWEC, would significantly increase the burden on utilities without a proportional improvement in the outcome. If Public Power customers or AWEC believe that reviewing these other years and accounts would be useful, they can access a utility's historical Appendix 1 filings, which are typically available from FERC after being submitted for approval.

BPA also disagrees that a variance analysis utilizing the utility's off-year informational filings would be beneficial. These informational ASC filings are not subject to discovery or other procedural requirements of a formal ASC review process. Instead, they ensure that BPA Staff remains informed about trends in a utility's costs. Thus, these informational filings are not a substitute for formal Appendix 1 filings conducted and vetted through a formal ASC review process. Furthermore, incorporating these informational filings alongside formal ASC filings for a variance analysis could lead to problematic results, creating more work and confusion for BPA Staff rather than aiding in the identification of potentially anomalous costs that warrant further review.

BPA also declines to adopt the suggestion by Public Power customers and AWEC to use the variance analysis to "normalize" the data in the FERC accounts. This change would fundamentally alter the "Base Period" basis for calculating a utility's ASC, which relies on actual costs. Introducing a normalization feature to the ASCM could increase a utility's costs in the Base Period year (if costs from other years are higher), thereby inflating its ASC. Conversely, it could decrease costs (if costs from other years are lower). BPA does not consider either of these outcomes reasonable, especially given that the ASCM is designed to produce an ASC of resources for a utility "in each year."[703]

Moreover, it is not clear what criteria or formulas would be used to "normalize" the data. Leaving this to BPA's discretion would put BPA in a role similar to that of a state utility commission—regulating based on policy considerations. Such a role would assuredly result in complex fact-finding, conflict, and litigation. BPA has seen value in the FERC Form

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[701] Public Power Comments (April) at 12; AWEC Comments (April) at 8.
[702] Public Power Comments (April) at 12; AWEC Comments (April) at 8.
[703] 16 U.S.C. § 839c(c)(1).

1 approach and declines to dramatically alter this methodology by attempting to "normalize" FERC Form 1 data.

Draft Decision

BPA will not expand the scope or impact of the variance analysis in the ASC Procedures.

12.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

BPA is in the process of assessing the potential environmental effects from the development and implementation of the proposed ASC methodology, consistent with the National Environmental Policy Act (NEPA), as amended, 42 U.S.C. § 4321 *et seq*. The NEPA review process is being conducted concurrently with the development of the ASC methodology and public stakeholder engagement process.

13.0 CONCLUSION

BONNEVILLE POWER ADMINISTRATION
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