**IOU Incremental Informal Comments in Response to BPA Incremental Preliminary Draft Average System Cost Methodology ("ASCM")**

**Submitted to REP2028@bpa.gov**

**February 10, 2026**

Avista Corporation, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. (together, the "investor-owned utilities" or "IOUs") offer the following incremental comments in response to the Bonneville Power Administration's ("BPA") Incremental Preliminary Draft Average System Cost Methodology ("Incremental Preliminary Draft ASCM").[1]

## I. Introduction and Background

On January 21, 2026, in the Post-2028 Residential Exchange Program ("REP") Average System Cost Methodology ("ASCM") proceeding, the IOUs filed comments on the Preliminary Draft ASCM that BPA posted on December 10, 2025 for informal comment ("IOU January 21 Comments").[2] On January 22, 2026, BPA announced that it would hold a workshop on January 27, 2026 to discuss the informal comments filed by stakeholders.[3] During the workshop, BPA addressed certain topics raised in comments and previewed certain changes to its proposed ASCM that formed part of an updated draft ASCM proposal published on February 3, 2026. BPA invited further stakeholder comment by February 10, 2026 ahead of BPA's intended release of the Full Draft ASCM on February 20, 2026.

The IOUs appreciate BPA incorporating certain ASCM changes requested by the IOUs in the IOU January 21 Comments. The IOUs also appreciate the opportunity to provide further comments here. Specifically, these incremental comments address the topics that the IOUs raised in the IOU January 21 Comments, including revisions proposed by BPA in the Incremental Preliminary Draft ASCM. The IOUs request that BPA address these comments directly in its Full Draft ASCM and reserve the right to provide additional comments following additional workshops and drafts of the ASCM.

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[1] Incremental Preliminary Draft Average System Cost Methodology (February 3, 2026), available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/incremental-draft-average-system-cost-methodology.doc, included as Attachment 1.

[2] The IOUs expressly incorporate the IOU January 21 Comments herein.

[3] The presentation that BPA gave at the January 27, 2026 workshop is available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20260127-post-2028-rep-ascm-informal-comments-workshop.pdf, included as Attachment 2.

## II. Purpose and Intent Behind the ASCM

The federally-owned hydropower system was created for the benefit of all Pacific Northwest citizens and to broadly support healthy and safe communities. In the Pacific Northwest Electric Power Planning and Conservation Act ("NWPA"),[4] Congress recognized that there was a growing imbalance in the allocation of the benefits of the federal hydropower system: customers of publicly-owned utilities were receiving substantial benefits from low-cost federal hydropower, while IOUs and our customers were paying significantly more for electricity.[5] Congress stepped in to balance these benefits through the creation of a new mechanism—the Residential Exchange Program ("REP")—that gave IOUs the right to sell their power to BPA at their average system cost and purchase an equivalent amount of power back from BPA through a physical exchange, resulting in cost and non-cost benefits to be passed through directly to our residential and small farm customers. The REP has delivered more than $10 billion in savings for IOU Pacific Northwest customers since 1980, with $4 billion of those savings coming since 2012. The fundamental purpose of the REP is to reduce the disparity resulting from the IOUs' lack of access to federal hydropower by spreading the benefits of the federal system to IOU residential and small farm customers. The REP thus allows all Northwest residential and small farm electricity customers, whether served by an IOU or by a consumer-owner utility ("COU"), to receive access to benefits from reliable, clean, low-cost, federally-owned hydropower.

Central to the operation of the REP is the determination of each exchanging utility's Average System Cost ("ASC"). The NWPA grants BPA the authority to determine the ASC based on a methodology developed through what BPA describes as "consultation proceedings." As BPA has acknowledged, "[t]he amount paid by BPA to the participating Utility is not a conventional wholesale power rate."[6] In particular, Section 5(c)(7) states:[7]

> 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. Such average system cost shall not include –

[4] 16 U.S.C. §§ 839-839h.
[5] *Id*. at §839(1).
[6] 2008 ASCM Record of Decision at 2.
[7] 16 U.S.C. § 839c(c)(7).

> (A) the cost of additional resources in an amount sufficient to serve any new large single load of the Utility;
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> (B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and
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> (C) any costs of any generating facility which is terminated prior to initial commercial operation.

The ASC framework is thus the statutory and methodological foundation for calculating the benefits that flow through the REP to IOU residential and small farm customers. Although a utility's ASC "shall be determined by the Administrator on the basis of a methodology developed for this purpose," such development must be "in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region," and also be "subject to review and approval by the Federal Energy Regulatory Commission."[8] Notwithstanding BPA's obligation to develop and periodically update the ASCM, ultimately the methodology can only be upheld by FERC and the Courts if it is consistent with the NWPA.[9] To that end, as discussed below, the IOUs provide additional informal comments on BPA's proposed ASCM revisions—some of which the IOUs support and some of which the IOUs oppose as being inconsistent with the NWPA.

## III. IOU Incremental Informal Comments on Select Proposals in the Incremental Preliminary Draft ASCM

### A. The IOUs Support Certain Proposed Revisions in the Incremental Preliminary Draft ASCM

The Incremental Preliminary Draft ASCM contains several revisions to the ASCM that align with the IOU January 21 Comments. The IOUs appreciate BPA's consideration of these changes.

#### 1. Energy Storage Plant

In the Preliminary Draft ASCM, BPA proposed to move the Energy Storage Plant accounts (FERC accounts 348, 353, and 361) into a single account and apply the Production/Transmission/Distribution ("PTD") labor ratio functionalization method.[10] The IOUs

[8] 16 U.S.C. § 839c(c)(7).
[9] Order No. 337, FERC Stats. & Regs. ¶ 30,506 at 30,738 (stating that the Commission can disapprove proposed ASC methodology only if it is inconsistent with the Northwest Power Act).
[10] Preliminary Draft ASCM § 301.4(v).

supported the consolidation of the accounts as being consistent with FERC Order No. 898, but argued that the use of the PTD functionalization method may not reflect the specific use of the installed batteries.[11] Accordingly, the IOUs recommended a direct functionalization method based on reasonable analysis of procurement conditions, interconnection status, or usage characteristics in the base year to allow utilities to reflect how energy storage devices contribute to a utility's ASC.[12] Based on the language in the Incremental Draft Preliminary ASCM, the IOUs understand that BPA will allow direct functionalization of the Energy Storage Plant account.[13] The IOUs support this change.

**2. Distribution Losses**

In the Preliminary Draft ASCM, BPA proposed to eliminate two of the three existing methods (Method 1 and Method 2) for determining a utility's distribution loss factor, leaving only Method 3.[14] The IOUs did not support this change and argued that the IOUs use both Method 1 and Method 3 to calculate distribution losses, and that BPA did not provide sufficient support for the proposed change.[15] In the Incremental Preliminary Draft ASCM, BPA proposes to allow the IOUs to use Method 1 or Method 3 to determine the utility's distribution loss factor.[16] The IOUs support this change.

**3. Determination of Average Short Term Purchased Power Prices and Sales for Resale Prices**

In the Preliminary Draft ASCM, BPA proposed to change the determination of average short term purchased power prices and sales for resale prices from three years to five years.[17] The IOUs requested that BPA retain the three-year weighted average calculation.[18] In the Incremental Preliminary Draft ASCM, BPA retained the three-year weighted average calculation.[19] The IOUs support this change.

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[11] IOU January 21 Comments at 3.
[12] *Id*.
[13] Incremental Preliminary Draft ASCM § 301.4(v).
[14] Preliminary Draft ASCM § 301.4(n).
[15] IOU January 21 Comments at 2-3.
[16] Incremental Preliminary Draft ASCM § 301.4(n)(1)-(2).
[17] Preliminary Draft ASCM § 301.5(b)(2)(ii)(A).
[18] IOU January 21 Comments at 5-6.
[19] Preliminary Draft ASCM § 301.5(b)(2)(ii)(A).

#### 4. Materiality Threshold for Inclusion of New Resources in the ASC

In the IOU January 21 Comments, the IOUs raised concerns with the existing materiality threshold and in-service requirements for new resources in the ASCM.[20] Specifically, the IOUs expressed concern that the existing materiality threshold and grouping requirements could prevent in-service resources from being reflected in the ASC, even when those resources are used and useful and contribute meaningfully to a utility's cost structure.[21] The IOUs urged BPA to explore methodologies that would allow for inclusion of all used and useful resources.[22] In the Incremental Preliminary Draft ASCM, BPA updated the materiality threshold and grouping requirements in the following way: for a resource that becomes operational after the Base Period, but prior to publication of the final ASC Report, that resource will need to show a change of 0.5% or greater in the utility's Base Period ASC to be considered material; for a resource addition or reduction during the Exchange Period, the resource addition or reduction must result in a 2.5% or greater change in the utility's Base Period ASC to be considered material.[23] The IOUs appreciate BPA's consideration of their comments and support this change.

#### 5. Revisions to the New Large Single Load ("NLSL") Methodology

In the Preliminary Draft ASCM, BPA proposed to change the treatment of NLSL costs in the ASCM by creating two NLSL periods representing "Base Period NLSL" and "Exchange Period NLSL," drafting a new treatment for determining a utility's resource cost to serve NLSL, removing the NLSL Exception, and removing the NLSL Formula rate.[24] In the IOU January 21 Comments, the IOUs requested that BPA delay implementing the NLSL proposal pending further discussion.[25] At the January 27 workshop, BPA Staff verbally provided additional clarification that its proposed changes to the NLSL methodology were to improve the calculation of the resource costs used to serve NLSLs, so those costs can be appropriately removed from the ASC as required by statute. The IOUs have reviewed the NLSL proposal in light of the clarification provided by BPA Staff and support the proposed revisions to the NLSL methodology.

### B. ASCM Provisions That the IOUs Do Not Support

#### 1. Limitation on Transmission Costs

BPA proposes to exclude all functionalized transmission costs other than those in (1) FERC Account 565 (Transmission of Electricity by Others) to account for third-party wheeling

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[20] IOU January 21 Comments at 7.
[21] *Id*.
[22] *Id*.
[23] Incremental Preliminary Draft ASCM § 301.5(c)(4).
[24] Preliminary Draft ASCM §§ 301.4(p), 301.5(c)(10).
[25] IOU January 21 Comments at 3.

transmission costs, and (2) FERC Account 447 (Sales for Resale).[26] The NWPA requires the inclusion of all transmission usage for load-serving purposes as a "cost" in a participating utility's ASC. This interpretation is supported by a plain reading of Section 5(c)(7) of the statute, the NWPA's legislative history, and BPA's own statutory- and policy-based arguments from 2008, which have only become more compelling in the intervening years. Accordingly, the IOUs do not support BPA's proposal to exclude most transmission costs from the ASCM, as such a change is inconsistent with the text and intent of the NWPA and with how the ASC has been calculated for decades.[27]

#### *a. BPA's Proposal to Limit Transmission Costs in the ASC is Inconsistent with the NWPA*

BPA's ASCM proposal is inconsistent with NWPA Section 5(c)(7), which is clear what BPA must consider, and must exclude, in calculating a utility's ASC through the ASCM.

First, in determining a utility's ASC, the statute unambiguously requires BPA to calculate the system "costs" of a participating utility to bring power to its residential and small farm loads—a notable portion of which indisputably includes transmission costs. BPA acknowledged this in its 2008 ROD, explaining that "[t]ransmission costs are a cost to a Utility of delivering power to load and should be included in the calculation of a Utility's ASC."[28] By excluding nearly all transmission costs from its proposed ASCM, BPA is not only ignoring the statute's unambiguous directive to calculate a participating utility's "costs" to deliver power to load, but the agency is also unfairly disadvantaging IOUs in the process. In particular, through its proposed ASCM changes, BPA appears to be recreating a fictionalized set of transmission costs that IOUs *do not* incur—namely, the imbedded transmission costs of non-IOUs paying the PF rate.[29] BPA's proposal clearly violates the requirements of Section 5(c)(7) by attempting to swap-in an unrelated set of "costs" as a proxy for IOU costs. This is particularly concerning given that, contrary to the relative proximity of COU systems to BPA resources and transmission, IOUs must, as BPA has observed, "[i]ncreasingly…rely on transmission to find the least cost resource available to serve load."[30] In other words, by attempting to mimic the transmission costs borne by COU customers, BPA is ignoring the NWPA's directive to base ASCM on actual *IOU* system costs and, in the

[26] Preliminary Draft ASCM § 301.4(x); Incremental Preliminary Draft ASCM § 301.4(x).

[27] The Incremental Preliminary Draft ASCM proposes to remove the treatment of transmission and distribution lines using the Commission's seven factor test contained in FERC Order 888. Because the IOUs disagree with BPA's transmission cost proposal, by extension, this change is also unnecessary, given that all appropriate transmission costs related to delivering power to load should remain in the ASC.

[28] 2008 ASCM Record of Decision at 126.

[29] *See* Public Power Council January 21, 2026 Comments at 3 ("We are supportive of BPA's proposal to remove all transmission costs from the ASC except for those which are in principle as near to the transmission costs included in the PF rate as possible").

[30] 2008 ASCM Record of Decision at 126.

process, BPA is understating the costs paid by IOU customers and impermissibly reducing the associated share of REP benefits.

Second, BPA is impermissibly creating additional categories of excluded costs not permitted in the statute. The statute expressly excludes only three categories of costs from inclusion in a utility's ASC: (a) the costs to serve any new large single load of the utility,[31] (b) the costs of additional resources in an amount sufficient to meet any additional load outside the region,[32] and (c) any costs of any generating facility which is terminated prior to initial commercial operation.[33] BPA's proposal to categorically exclude most transmission costs is a direct violation of the NWPA. As explained above, the costs for transmission to deliver IOU resources to load are a legitimate system cost that should be accounted for as part of each IOU's respective ASC.

Third, legislative history confirms that the statutory language requires the ASCM to capture all of a utility's costs with limited exceptions. Contemporaneous statements and committee reports make clear that the ASCM authorized by Section 5(c)(7) was intended to capture *all* utility costs, save for the select exceptions noted in the statute. In the November 19, 1980 Senate Congressional Record, Senator McClure explained that the ASCM developed by BPA should pay 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."[34] By excluding most transmission costs from the ASCM, 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—leading to an "extra financial burden" that Congress expressly prohibited.

#### ***b. BPA's Proposal to Limit Transmission Costs in the ASC is Inconsistent with BPA's Own Policy***

Beyond the plain language of the NWPA and its legislative history, BPA has already articulated strong policy reasons for including all relevant transmission costs in ASC. In the 2008 ASCM Record of Decision ("ROD"), BPA Staff explained that transmission costs have always been treated as a component of ASCs under prior BPA-developed methodologies, and that this treatment remained appropriate in light of significant changes in the wholesale power and transmission markets between the 1984 ROD and 2008.[35] Utilities had gained the ability to purchase power from a broader pool of suppliers at market-clearing prices (e.g., through indices such as Mid-C) and had come to rely more heavily on independent power producers selling into

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[31] 16 U.S.C. § 839c(c)(7)(A).
[32] 16 U.S.C. § 839c(c)(7)(B).
[33] 16 U.S.C. § 839c(c)(7)(C).
[34] Cong. Rec. S 14698 (daily ed. Nov. 19, 1980) (statement of Sen. James McClure).
[35] 2008 ASCM Record of Decision at 128.

the market or under long-term PPAs.[36] BPA acknowledged that, to serve load at least cost, utilities have become increasingly reliant on transmission to import generation into their service territories, even as regional underinvestment in transmission created a more constrained grid than existed in 1984.[37] As BPA aptly summarized:

> Electric utilities have a variety of robust ways to acquire generation to serve retail load, most of which entail incurring transmission costs. For example, utilities can: (1) rely on wholesale power markets; (2) build centralized generation units close to the fuel source; (3) build generation close to the load center and transport the fuel source (e.g. coal by rail); (4) import power from outside the region; and (5) purchase power under long-term power purchase agreements with independent power producers. In addition, many large power plants are owned by more than one Utility.[38]

Given this diversity of resource acquisition strategies, BPA stated that "excluding transmission costs from the ASC calculation would have adverse effects on Utilities."[39] BPA explained further that "exclusion of the transmission component of electricity production and delivery would ***introduce an inequity*** between Utilities that develop resources close to their service territory and those that develop geographically distant resources."[40]

BPA's compelling rationale remains equally valid and applicable today as it did in 2008—and the agency has failed to articulate a reasoned analysis for moving away from this change in policy. The factual and policy foundations BPA Staff relied upon in 2008 remain fully applicable in 2026, and subsequent developments only reinforce the conclusion that all transmission costs should continue to be included in the ASC. Nothing has changed since the 2008 ROD to suggest that a substantial portion of transmission costs should now be excluded; to the contrary, the same evolution in wholesale power and transmission markets has continued, and, moreover, the region is now subject to stringent decarbonization mandates that further increase utilities' reliance on transmission. For example, since 2008, Washington and Oregon have adopted robust carbon compliance regimes that obligate the IOUs to decarbonize their retail electricity sales.[41] Whereas BPA's 2008 analysis focused primarily on economic tradeoffs between siting generation near fuel sources or near load (often coal-based), utilities now have state-mandated reasons to procure

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[36] *Id*.
[37] *Id*.
[38] *Id*.
[39] *Id*. at 129.
[40] *Id*. (emphasis added) (citing 73 Fed. Reg. 7270, 7275 (Feb. 7,2008).
[41] Oregon law requires such decarbonization by 2040 with interim reductions of 80% by 2030 and 90% by 2035. Washington law requires decarbonization by achieving greenhouse gas neutrality by 2030 and zero emissions or fully renewable generation by 2045.

renewable resources that are frequently located far from load and necessarily require transmission to deliver energy to customers. Excluding transmission costs from ASCs in this context would effectively penalize exchanging utilities for complying with state law. In addition, reliance on transmission is no less important as the region transitions to organized day-ahead markets such as EDAM and SPP Markets+, which both fundamentally require utility participants to self-schedule their underlying transmission rights to serve load.

BPA has failed to explain why the inequities clearly present in 2008, which animated its decision to include all relevant transmission costs in the ASCM, are somehow missing today. Under the Administrative Procedure Act, an agency rule that implements a policy change by amending or repealing an existing rule is subject to arbitrary and capricious review.[42] The Supreme Court has held that an agency must provide a reasoned analysis for the departure from its own policy.[43] All of the justifications that BPA articulated in 2008 apply with equal, if not greater, force today. Indeed, as noted above, additional regulatory compliance and market forces compound how much the IOUs must rely on transmission systems to access distant and renewable resources.

For all of these reasons, continued inclusion of all transmission costs in the ASCM is both essential and consistent with the NWPA. BPA's unexplained departure to the contrary, despite consistent feedback from the IOUs and other stakeholders, is not only arbitrary and capricious, but also violates the NWPA.

### 2. Limitation on Injuries and Damages

In the Incremental Preliminary Draft ASC, BPA proposes to limit the inclusion of charges in FERC Account 925 (Injuries and Damages) to charges in Account 925 that are one percent or less of a utility's total system costs.[44] For any amount over the one percent threshold, BPA further proposes to require the utility to make a showing of where those charges were approved by a state public utility commission ("PUC") for retail rate recovery before the charges may be included in the ASC.[45]

BPA's proposal raises significant concerns for the IOUs. First, as with BPA's proposal to limit the inclusion of certain transmission costs, the limitation of Account 925-related costs has no basis in the statutory text. As noted above, the NWPA expressly identifies only three categories

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[42] 5. U.S.C. § 706(2)(A) (emphasis added).
[43] *See, e.g., Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41, 103 S. Ct. 2856, 77 L.Ed.2d 443 (1983) (holding that "[a]n agency changing its course by rescinding a rule is obligated to supply a reasoned analysis for this [policy] change beyond that which may be required when an agency does not act in the first instance.")
[44] Preliminary Draft ASCM §§ 301.4(w).
[45] *Id*.

of costs that are excluded from a utility's ASC: (a) the costs to serve any new large single load of the utility,[46] (b) the costs of additional resources in an amount sufficient to meet any additional load outside the region,[47] and (c) any costs of any generating facility which is terminated prior to initial commercial operation.[48] This provision of the NWPA establishes narrow, specific exceptions to the "costs" included in determining a utility's ASC, and does not exclude a utility's injuries and damages costs. As with transmission costs, a utility's injuries and damages costs are legitimate system costs that should be reflected in each IOU's ASC. Because 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.

Second, beyond BPA's clear lack of statutory authority under the plain text of the NWPA to limit or exclude a utility's injuries and damages costs, BPA's proposal to limit Account 925 costs to one percent of a utility's total system costs and require PUC approval of costs above one percent is also arbitrary and capricious in several respects. At the outset, BPA has failed to articulate a justifiable basis for proposing limitations on Account 925 at all. This account can encompass numerous types of injury and damage-related costs legitimately incurred by utilities (e.g. employee injury costs, auto accident-related injury claims, etc.), and BPA provides no explanation for such a broad stroke limitation on this Account. This is particularly egregious given that BPA does not appear to hold itself (and, thus, its own cost recovery) to such restrictions. Moreover, even if general limitations on Account 925 were appropriate, BPA provides no justification for why one percent of a utility's total system costs would be an appropriate threshold to impose. The record is bereft of any explanation whatsoever for this seemingly randomly selected percentage, and BPA Staff have failed to articulate any justification in the workshops to date.

Finally, if a utility's Account 925 costs surpass the arbitrarily-chosen one percent threshold, BPA furthermore inappropriately limits any additional Account 925 costs to those approved by PUCs. Such a proposal is both short-sighted and administratively burdensome. As explained previously, PUC orders do not always expressly address injuries and damages and IOUs routinely receive recovery of Account 925 costs in transmission rates subject to FERC review and approval.[49] BPA provides no explanation for why Account 925 costs are any less legitimate simply because they are approved for rate recovery by FERC, as opposed to a PUC. In addition, BPA's narrow focus on retail-level recovery ignores the administrative efficiency and fundamental fairness underlying the use of utility FERC Form 1 accounts in the first place. Reliance on retail

[46] 16 U.S.C. § 839c(c)(7)(A).
[47] 16 U.S.C. § 839c(c)(7)(B).
[48] 16 U.S.C. § 839c(c)(7)(C).
[49] IOU January 21 Comments at 4.

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.

Simply put, under the NWPA, all Account 925 costs must be eligible for inclusion in the ASCM, regardless of whether they exceed an arbitrary percentage threshold set by BPA, or whether they are recovered through FERC- or state-jurisdictional rates. BPA's proposal is unworkable, inconsistent with the NWPA, arbitrary and capricious, and should not be adopted.

**3. Definition of "Priority Firm Power"**

The IOUs continue to oppose the proposed deletion of the definition of "Priority Firm Power" as raised in the IOU January 21 Comments.[50] BPA's current definition of "Priority Firm Power" accurately recognizes that, under the NWPA, BPA is obligated to make "electric power (capacity and energy) … continuously available for direct consumption or resale to… Utilities 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 Sales Agreements with Bonneville." Moreover, the definition recognizes that "deliveries" of such power may be reduced or interrupted only as permitted under the IOU's RPSAs with BPA. Accordingly, BPA's proposed deletion of this definition is inconsistent with the NWPA's requirement that BPA implement the REP as a physical exchange.[51]

**4. Forecasting the Electric Market Price for Power Purchases Needed to Meet Load Growth Not Met by Major Resource Additions**

In the IOU January 21 Comments, the IOUs identified two issues within the existing ASCM that were not addressed in the Preliminary Draft ASCM, but have the potential to materially affect the calculation of the ASC and, accordingly, REP benefits. In the Incremental Preliminary Draft ASCM, BPA incorporated changes to the materiality threshold that the IOUs support.[52] However, BPA has not addressed the issues that the IOUs raised regarding the ASCM Forecast Model and the methodology used to forecast electric market prices for power purchases required to serve load growth not met by major resource additions. The IOUs reiterate the recommendation 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.

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[50] Preliminary Draft ASCM § 301.2; *see also* IOU January 21 Comments at 6.

[51] *See* IOU Comments in Response to BPA Draft Post-2028 Residential Purchase and Sale Agreement, submitted January 21, 2026.

[52] Incremental Preliminary Draft ASCM § 301.5(c)(4).

### C. BPA has Failed to Meaningfully Engage with Stakeholders on ASCM Issues, as Required by the NWPA

Finally, BPA has not engaged in the kind of meaningful, cooperative consultation that the NWPA requires. As noted above, the statute directs BPA to develop a methodology for determining utility ASCs "in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region." Legislative history demonstrates that Congress intended for the consultation process to be cooperative, allowing BPA's customers to share "information, concerns, and expertise" to shape the decision-making process from its earliest stages.[53] These public process and consultation provisions were not casually inserted into the statute, but rather, constitute a core part of BPA's decision-making process with respect to the ASCM in particular. Indeed, as shown in the congressional record:

> "…The purpose of these provisions is not simply to require input from the public and from BPA's customers at particular, specified points in the decision-making process. Rather, the intent is to have such consultation be an ongoing, comprehensive pattern in the conduct by the council and by BPA of all their respective functions. The spirit should be one of cooperation and respect, not one of aloof Government insulated from interested parties by layers of formalism and procedure…information, concerns and expertise can all shape the decision-making process from its earliest stages…."[54]

BPA's process to engage the "Administrator's customers, and appropriate State regulatory bodies in the region" in the development of the ASCM has been perfunctory at best and falls short of the meaningful, cooperative consultation required by statute. Since BPA initiated the ASCM proceeding in October of 2025, BPA has only held three workshops to discuss the proposed changes to the ASCM—which had not been updated since 2008. Those workshops were the only venue for stakeholders to hear and discuss BPA's rationale for its proposed ASCM changes, which, as outlined throughout Part III.B above, has been incomplete and inconsistent with longstanding BPA practice. Further compounding this problem, BPA afforded stakeholders only a single opportunity to comment on the substantial changes proposed in the December 10 Preliminary Draft ASCM. BPA's January 27, 2026 workshop—held only a few days after initial comments were received—provided IOUs and other stakeholders with only BPA Staff's verbal reactions to some of the concerns outlined in stakeholder comments. Rather than meaningfully engaging with this feedback, and thoughtfully expand the ASCM process timeline to accommodate iterative ASCM changes in response, BPA instead spent the substantial majority of the workshop previewing a new

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[53] Cong. Rec. S 14691 (daily ed. Nov. 19, 1980) (statement of Sen. Henry Jackson).

[54] *Id*.

set of iterative ASCM changes with apparently little, or no, consideration of the feedback that BPA had requested.

BPA has still not provided any substantive, written explanation or justification for its evolving ASCM changes beyond the workshop materials themselves. Although BPA expressly promised stakeholders during the January 27, 2026 workshop that it would provide written explanations for its revisions to the Incremental Draft Preliminary ASCM when it was published on February 3, 2026, BPA released only a redline comparison against the Draft Preliminary ASCM issued on December 10, 2025. A bare redline, without accompanying explanation from BPA, forces the IOUs to speculate about BPA's reasons and to reverse-engineer BPA's rationale for its changes.

In sum, although the IOUs agree with some of the changes proposed by BPA in the Incremental Draft Preliminary ASCM, overall, BPA's ASCM process to-date has fallen well short of the NWPA's "consultation" requirements and BPA's other agency obligations to explain its reasoning and decision-making. BPA has failed to explain the rationale behind many of its proposed ASCM revisions—particularly with regard to its policy reversal on transmission costs—which would impose an adverse and inequitable burden on IOU customers. As a result of a substantively and procedurally deficient ASCM process, the IOUs are left to analyze BPA's arbitrary decisions and unexplained departures from its own policies, without the transparency or meaningful consultation that the NWPA expressly requires.

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The IOUs appreciate BPA's consideration of these incremental informal comments to the Incremental Preliminary Draft ASCM and request that BPA address these comments directly in its Draft ASCM.

Attachment 1
Incremental Preliminary Draft Average System Cost Methodology
February 3, 2026

# ~~Preliminary~~ Incremental Draft of BPA's 2026 Average System Cost Methodology

Part I: FERC Regulation

Word document page 3~~2~~

Part II: BPA's Rules of Procedure for ASCs

Word document page 45~~34~~

Bonneville Power Administration

# ASC Methodology Part I

FERC Regulation

**PART I**

PART 301--AVERAGE SYSTEM COST METHODOLOGY FOR SALES FROM UTILITIES TO BONNEVILLE POWER ADMINISTRATION UNDER NORTHWEST POWER ACT

Sec.

Authority: 16 U.S.C. 839-839h.

## 18 CFR § 301.1

§ 301.1 Applicability.

The regulations in this part apply to the sales of electric power by any Utility to the Bonneville Power Administration (Bonneville) under Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. 839c(c).

## 18 CFR § 301.2

§ 301.2 Definitions.

For purposes of this methodology, the following definitions apply:

Account(s). The Accounts prescribed in the Commission's Uniform System of Accounts.

Appendix 1. Appendix 1 is the electronic form on which a Utility reports its Contract System Cost, Contract System Load, and other necessary data to Bonneville for the calculation of the Utility's Average System Cost.

Average System Cost (ASC). The rate charged by a Utility to Bonneville for the agency's purchase of power from the Utility under Section 5(c) of the Northwest Power Act for each Exchange Period, and the quotient obtained by dividing Contract System Cost by Contract System Load. 16 U.S.C. 839c(c).

Average System Cost Delta (ASC Delta). The change in a Utility's ASC during the Exchange Period resulting from the inclusion in the Average System Cost forecast model of costs, loads, revenues, and other information related to the commercial operation of a major resource addition or reduction that was identified in the Utility's ASC filing.

Average System Cost Forecast Model (ASC Forecast Model). The model Bonneville uses to escalate a Utility's costs, revenues, and other information contained in the Appendix 1 to calculate the Exchange Period ASC.

Average System Cost Review Process (ASC Review Process). The administrative proceeding conducted concurrent to Bonneville's rate case proceedings and pursuant to Bonneville's ASC Review Rules of Procedures in which Bonneville determines a Utility's ASC for the applicable Exchange Period.

Base Period. The calendar year of the most recent FERC Form 1 data.

Base Period ASC. The ASC determined in the Review Period using the Utility's Base Period data and additional specified data.

Confidential Information. The Utility's information that falls within an exemption from the mandatory disclosure requirements of the Freedom of Information Act, 5 U.S.C. § 552, or is otherwise exempt from public disclosure. It does not include any document or information obtained by BPA or other parties to this proceeding from secondary sources (except where such information was obtained under a separate protective order or confidentiality agreement).

Commission. Federal Energy Regulatory Commission.

Contract System Cost. The Utility's resource costs for production, including power purchases and conservation measures, which costs are includable in the Utility's Appendix 1 pursuant to the provisions of this ASCM. Costs of transmission, unless otherwise provided in this ASCM, are not included in Contract System Cost. Under no circumstances will Contract System Cost include costs excluded from ASC by Section 5(c)(7) of the Northwest Power Act. 16 U.S.C. 839c(c)(7).

Contract System Load. The total regional retail load included in the most recently filed FERC Form 1 as adjusted pursuant to the ASC Methodology.

Direct Analysis. An analysis, including supporting documentation, prepared by the Utility that proposes to functionalize the costs, debits, credits, and revenues in an Account to the Production, Transmission, and/or Distribution/Other functions of the Utility.

Escalator. A factor used to adjust an Account in the Base Period ASC filing to the value for the period of the Exchange Period ASC.

Exchange Load. All residential, apartment, seasonal dwelling and farm electrical loads eligible for the Residential Exchange Program under the terms of a Utility's Residential Purchase and Sales Agreement.

Exchange Period(s). The period during which a Utility's Bonneville-approved ASC is effective for the calculation of the Utility's Residential Exchange Program benefits. The initial Exchange Period under this ASC methodology is from October 1, 2028, through September 30, 2030. Subsequent Exchange Periods will be the period of time concurrent with Bonneville's wholesale power rate periods beginning October 1 or, if not beginning October 1, then beginning on the effective date of Bonneville's subsequent wholesale power rate periods.

Exchange Period ASC. The Base Period ASC escalated to a year(s) consistent with the Exchange Period.

FERC Form 1. The annual filing submitted to the Federal Energy Regulatory Commission, required by 18 CFR 141.1.

Functionalization. The process of assigning a Utility's costs, debits, credits, and revenues in an Account to the Production, Transmission, and/or Distribution/Other functions of the Utility.

Jurisdiction. The service territory of the Utility within which a particular regulatory body has authority to approve the Utility's retail rates. Jurisdictions must be within the Pacific Northwest region as defined in Section 3(14) of the Northwest Power Act. 16 U.S.C. 839a(14).

Labor Ratios. The ratios that functionalize costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/Other functions included in the Utility's most recently filed FERC Form 1.

Mid-Rate Period Adjustment. Additions, removals, or alterations to load or resource assumptions in the Appendix 1 that take effect during the Rate Period.

New Large Single Load. That load defined in Section 3(13) of the Northwest Power Act, and determined by Bonneville as specified in power sales contracts and Residential Purchase and Sales Agreements with its Regional Power Sales Customers. 16 U.S.C. 839a(13).

PF Exchange Rate (PFx). The rate for exchange power established by BPA in a proceeding pursuant to Section 7(i) of the Northwest Power Act, or its successor.

Public Purpose Charge. Any charge based on a Utility's total retail sales in a Jurisdiction that is provided to independent entities or agencies of state and local governments for the purpose of funding within the Utility's service territory one or both of the following:

(a) Conservation programs in lieu of Utility conservation programs;

or

(b) Acquisition of renewable resources.

Rate of Return (ROR). Weighted return on equity and debt.

Rate Period. The period during which Bonneville's wholesale power rates are effective. The period is coincident with the Exchange Period.

Regional Power Sales Customer. Any entity that contracts directly with Bonneville for the purchase of power under Sections 5(b) (16 U.S.C. 839c(b)), 5(c) (16 U.S.C. 839c(c)), or 5(d) (16 U.S.C. 839c(d)) of the Northwest Power Act for delivery in the Pacific Northwest region as defined by Section 3(14) of the Northwest Power Act. 16 U.S.C. 839a(14).

Residential Purchase and Sales Agreement (RPSA). The contract under Section 5(c) of the Northwest Power Act between Bonneville and a Utility that defines and implements the power purchase and sale under the Residential Exchange Program.

Review Period. The period of time during which a Utility's Appendix 1 is under review by Bonneville. The Review Period begins on or about June 1, or such other date as may be established by BPA, and ends no later than concurrent with BPA's final rate case decision.

Regulatory Body. A state commission, Consumer-owned Utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

Utility. A Regional Power Sales Customer that has executed a Residential Purchase and Sales Agreement.

18 CFR § 301.3

§ 301.3 Filing Procedures.

(a) Bonneville's filing procedures. The ASC Review Rules of Procedure established by Bonneville's Administrator provide the filing requirements for all Utilities that file an Appendix 1 with Bonneville. Utilities must file Appendix 1s, ASC forecast models, and other required documents with Bonneville in compliance with Bonneville's ASC review procedures as specified in the ASC Review Rules of Procedure for BPA's ASC Review Processes.

(b) Exchange Period. The Exchange Period will be equal to the term of Bonneville's Rate Period. ASCs will change during the Exchange Period only for the reasons provided in § 301.4.

## 18 CFR § 301.4

§ 301.4 Base Period Average System Cost.

(a) A Utility’s Base Period Average System Cost (ASC) will be determined pursuant to the provisions of section 301.4. The Utility’s Base Period ASC will be calculated using the data populated into that Utility’s Appendix 1.

(b)Appendix 1 is the form on which a Utility reports its Contract System Cost, Contract System Load, and other necessary data for the calculation of ASC. Appendix 1 is an electronic template consisting of seven primary schedules and several supplemental tabs that must be completed by the Utility in accordance with these instructions and with the provisions of the Table 1 Endnotes.

(c) Appendix 1 filings must be accompanied by a signed Senior Financial Officer Attestation (Attachment A to the Rules of Procedure).

(d) The primary source of data for a Utility's Appendix 1 filing is the Utility's FERC Form 1 filings with the Commission corresponding to the Base Period ASC. Any items not applicable to the Utility must be identified.

(e) The Appendix 1 template is available electronically at https://www.bpa.gov/energy-and-services/power/residential-exchange-program. The primary schedules are:

(1) Schedule 1: Plant Investment/Rate Base

(2) Schedule 1A: Cash Working Capital

(3) Schedule 2: Capital Structure and Rate of Return

(4) Schedule 3: Expenses

(5) Schedule 3A: Taxes

(6) Schedule 3B: Other Included Items

(7) Schedule 4: Average System Cost

(8) Other supplemental tabs required for the calculation of the Utility's ASC.

(f) The filing Utility must reference and attach work papers, documentation and other required information that support costs and loads, including details of allocation and functionalization. All references to the Commission's Accounts are to the Commission's Uniform System of Accounts, as amended by subsequent Commission actions. The costs includable in the attached schedules are those includable by reason of the definitions in the Commission's Accounts.

(1) If the Commission's Accounts are later revised or renumbered, any changes will be incorporated into the Table 1 and the Appendix 1 by reference, except to the extent Bonneville determines that a particular change results in a change in the type of costs allowable for ASC purposes. In that event, Bonneville will address the changes, including escalation rules, in its ASC Review Process for the following Exchange Period.

(g) Bonneville may require a Utility to account for all transactions with affiliated, associated, and/or subsidiary companies as though these entities were owned in whole or in part by the Utility, if necessary, to properly determine and/or functionalize the Utility's costs.

(h) A Utility operating in more than one Pacific Northwest Jurisdiction must file one Appendix 1.

(i) A Utility operating in a Jurisdiction within the Pacific Northwest and within Jurisdictions outside the Pacific Northwest must allocate its total system costs among its Jurisdictions within the Pacific Northwest and outside the Pacific Northwest in accord with the same allocation methods and procedures used by the Regulatory Body(ies) to establish Jurisdictional costs and resulting revenue requirements. The Utility's Appendix filing must include details of the allocation.

(1) ~~(1)~~ The allocation must exclude all costs of additional resources used to meet loads outside the Pacific Northwest, as required by section 5(c)(7) of the Northwest Power Act. All Schedule entries and supporting data must be in accord with Generally Accepted Accounting Principles and Practices as these principles and practices apply to the electric utility industry.

(j) Average System Cost methodology functionalization. Functionalization of each Account included in a Utility's ASC must be according to the functionalization prescribed in Table 1, Functionalization and Escalation Codes. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account, with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded. Demand-side management (DSM) and demand response (DR) are not conservation. The Direct Analysis must be consistent with the directions provided in this section.

(k) Functionalization codes.

(1) DIRECT--Direct Analysis.

(2) PROD--Production.

(3) TRANS--Transmission.

(4) DIST--Distribution/Other.

(5) PTD--Production, Transmission, Distribution/Other Ratio.

(6) TD--Transmission, Distribution/Other Ratio.

(7) GP--General Plant Ratio.

(8) GPM--General Plant Maintenance Ratio.

(9) PTDG--Production, Transmission, Distribution/Other, General Plant Ratio.

(10) LABOR--Labor Ratio.

(l) Functionalization requirements.

(1) Functionalization of certain Accounts may be based on Direct Analysis or with a default ratio associated with that specific Account as shown in Table 1. 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 Bonneville.

(2) The Utility must submit with its Appendix 1 all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs, revenues, debits or credits based upon the actual and/or intended functional use of those items. Failure to submit the documentation will result in the entire account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

(m) Functionalization methods.

(1) Direct Analysis, if allowed or required by Table 1, assigns costs, revenues, debits and credits to the Production, Transmission, and/or Distribution/Other function of the Utility. The only exception to this requirement is for Accounts that include conservation-related costs. Subject to the provisions of paragraph (m) of this section, a Utility may conduct a Direct Analysis on any Account that contains conservation-related costs. The Direct Analysis performed by a Utility is subject to

Bonneville review and approval.

(2) Bonneville will not allow a Utility to use a combination of Direct Analysis and a prescribed functionalization method for the same Account, unless otherwise instructed via an Endnote. The Utility can develop and use a functionalization ratio, or use a prescribed functionalization method, if the Utility, through Direct Analysis, can justify how the ratio reflects the functional nature of the costs, revenues, debits, or credits included in any Account.

(3) A Utility that wishes to include advertising and promotion costs related to conservation will use Direct Analysis.

(4) If a Utility records conservation costs in an Account that is functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. The presence of conservation-related costs in an Account does not authorize the Utility to perform a Direct Analysis on the entire Account. This option allows a Utility to assign conservation costs in the specified Account to Production based on analysis and support from the Utility that demonstrates the cost assignment is appropriate.

(5) The Utility must submit with its ASC filing all work papers, documents, and other materials that demonstrate the functionalization contained in its Direct Analysis and assign costs based upon the actual and/or intended functional use of those items. Failure to submit the documentation will result in the entire Account being functionalized to Distribution/Other for all schedules with the exception of items included in Schedule 3B, Other Included Items, where certain Accounts must be functionalized to Production as appropriate.

(n) Method to Calculate Distribution Losses. The losses will be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss factor will be measured using one of the following methods:

(1) Method 1, Distribution Loss Study:

(i) Losses will be established according to a study (engineering, statistical and other) that is submitted to Bonneville by the Utility, that will be subject to review by Bonneville. This study must be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load. Distribution losses must include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

The study will be used to calculate distribution losses for the Utility's Base Period ASC. Distribution l~~L~~oss studies are valid for 7~~seven~~ years after the publication date of such study. If the distribution loss study is not valid~~At which point~~, the Utility must provide a new distribution loss study or default to Method 2.

~~(1)~~(2) Method 2, Default: Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1.

(i) From this 5-year total system loss factor, subtract Bonneville's 12-month weighted average transmission system loss factor.

(ii) The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

(o) The 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. For multi-Jurisdictional Utilities, a Utility will first determine the WCC for each Jurisdiction. The Utility will then determine a region-wide WCC based on applying the WCC times the Regulatory Body approved rate base from the same rate order used for the WCC.

(1) The return on equity (ROE) used in the WCC calculation will then be grossed up for Federal corporate income taxes at the marginal then in-effect Federal corporate income tax rate using the following formula to determine the percentage increase in the ROE used for ASC determination:

(2) FIT Adder = {(WCC – (Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}

(3) The sum of the FIT Adder plus the ROE equals the Federal corporate income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal corporate income tax adjusted weighted cost of capital (TAWCC). The TAWCC will be multiplied by the total rate base from Schedule 1 to determine the return component on Schedule 2.

(4) For Utilities that do not use depreciation for Jurisdictional rate setting, the return will be equal to the weighted cost of debt times the rate base included in the ASC filing.

(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 will be based first on the average costs of 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 legacy NLSLs online prior to the effective date of this 2026 ASCM, the resource costs will be based on the Utility's Base Period ASC.

(3) ASCs will only be adjusted for loads that have been designated as NLSLs prior to the end of the Base Period.

(q) Contract System Costs must reflect the costs and the revenues arising from conservation and/or retail rate schedules.

(r) Cash working capital (CWC) is a ratemaking convention that is not included in the FERC Form 1, but is part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a Utility, Bonneville will allow no more than 1/8 of the functionalized costs of total production expenses, and Administrative and General expenses less purchased power, fuel costs, and Public Purpose Charge.

(s) Conservation costs are costs of energy audits and actual or planned load reduction resulting from direct application of a conservation measure (Northwest Power Act, Section 3(19)(B)) by means of physical improvements, alterations, devices, or other installations that are measurable in units. Conservation costs funded by the Utility will be functionalized to Production in the Utility's Average System Cost. Conservation costs incurred to promote changes in consumer behavior including costs attributable to brochures, advertising, pamphlets, leaflets, and similar items will be functionalized by Direct Analysis with a default to Distribution/Other. Conservation surcharges imposed pursuant to Section 4(f)(2) of the Northwest Power Act or other similar surcharges or penalties imposed on a Utility for failure to meet required conservation efforts will also be functionalized to Distribution/Other. Conservation and associated costs must be generally consistent with the Northwest Power and Conservation Council's resource plan as determined by Bonneville's Administrator.

(t) Public Purpose Charges collected by Utilities and distributed to independent third party non-profit organizations or state and local entities (recipient organizations) for the purposes of acquiring conservation and renewable resources shall be determined on a utility-by-utility basis through Direct Analysis. The ASC Methodology will only allow the costs of conservation and renewable resource development, acquisition and implementation. Allowable costs include costs associated with energy audits and advertising and promotion of conservation and renewable resources.

(1) In order to be included in Contract System Costs, the renewable resources acquired by the recipient must be included in the Utility's Integrated Resource Plan or similar document and, in the case of dispatchable resources, must be included in the Utility's resource stack.  Bonneville will treat expenditures of Public Purchase Charge funds similar to Utility conservation costs.

(u) All revenues associated with the production function of a Utility will be functionalized to production.

(v) Treatment of Energy Storage~~ Plant~~ costs: Bonneville will allow DIRECT functionaliz~~e~~ation of Energy Storage Plant~~, Energy Storage Expenses: Operation, and Energy Storage Expenses: Maintenance  costs using~~or~~with the~~ PTD as default ratio. Energy Storage Expenses: Operation, and Energy Storage Expenses: Maintenance costs will apply~~follow~~ the same functionalization as~~of~~ Energy Storage Plant.

(w) Injuries and Damages. FERC Account 925 will initially be functionalized by the LABOR ratio. If ~~T~~the ~~percentage of~~ FERC Account 925 costs functionalized to PROD ~~shall~~ do not exceed 1% of the Utility's total system cost, this amount is included in ASC~~ absent State Commission(s) approval for inclusion in retail rates.~~ . If the FERC Account 925 costs functionalized to PROD exceed 1% ~~included costs functionalized to PROD exceed 1%,~~the Utility may provide State Commission orders of costs~~ only the costs~~ approved for recovery ~~by the Utility's state commission(s)~~ into its retail rates during the Base Period.~~ shall be included in its ASC. The Utility must provide commission orders of such approval.  Costs in FERC Account 925 will be functionalized to Dist/Other.~~Absent state commission(s) rate order(s) ~~a~~Account 925 is capped at 1%.

(1) State approved Injuries and Damages. ~~Costs from FERC Account 925 approved for retail rate recovery by state commissions will be functionalized using the Labor Ratio.~~ The ASCM will not allow double recovery of these costs housed in other accounts (e.g. Regulatory Assets or Liabilities).

(x) Transmission costs. Unless otherwise provided in paragraph (x) of this section, transmission costs are not included in ASC.

(1) Transmission of Electricity by Others (Wheeling), Account 565. Costs included in Account

565 will be functionalized to Production and included in the Utility's ASC; provided however that costs included in Account 565 that are payable to an affiliated, associated, or subsidiary company will be functionalized to transmission and excluded from ASC.

(2) Transmission (delivery) costs associated with Sales for Resale, Account 447. Costs included in Account 447 are assumed to include trans-mission costs associated with Sales for Resale. The Utility may record additional transmission costs not included in Sales for Resale in Schedule 3B in the line item "Transmission for Sales for Resales" and perform a Direct Analysis.

(y)Demand-side management (DSM) and/or Demand Response (DR). DSM and/or DR related costs recorded in Account 908 shall be functionalized to Dist/Other unless the Utility performs a Direct Analysis. DSM and DR costs recorded in any other account shall be functionalized based on that account's default method.

§ 301.5 Exchange Period Average System Cost Determination.

(a) A Utility's Exchange Period Average System Cost (ASC) will be determined pursuant to the provisions of section 301.5.

(1) This section describes the method Bonneville will use to escalate the Base Period ASC to and through the Exchange Period to calculate the Exchange Period ASC.

(2) Bonneville will escalate the Bonneville-approved Base Period ASC to the midpoint of the Exchange Period. Midpoint ASCs are derived by averaging the ASC at the start and end date of the Exchange Period.

(3) For purposes of the escalation referenced in paragraph (a)(2) of this section, Bonneville will use the following codes in the ASC forecast model to calculate the Exchange Period ASCs:

(i) A&G--Administrative and General.

(ii) CACNT--Customer Account.

(iii) CD--Construction, Distribution Plant.

(iv) CONSTANT--Constant.

(v) CSALES--Customer Sales.

(vi) CSERVE--Customer Service.

(vii) COAL--Coal.

(viii) DMN--Distribution Maintenance.

(ix) DOPS--Distribution Operations

(x) HMN--Hydro Maintenance.

(xi) HOPS--Hydro Operations.

(xii) INF--Inflation.

(xiii) NATGAS--Natural Gas.

(xiv) NFUEL--Nuclear Fuel.

(xv) NMN--Nuclear Maintenance.

(xvi) NOPS--Nuclear Operations.

(xvii) OMN--Other Production Maintenance.

(xviii) OOPS--Other Production Operations.

(xix) SNM--Steam Maintenance.

(xx) SOPS--Steam Operations.

(xxi) TMN--Transmission Maintenance.

(xxii) TOPS--Transmission Operations.

(xxiii) WAGES--Wages.

(4) Table 1 identifies which codes from paragraph (a)(3) of this section apply to the line items and associated FERC Accounts in the Appendix 1. Bonneville will use a third-party as the source of data for the escalation codes identified in paragraph (a)(3) of this section, except for the NATGAS and CONSTANT codes. For the NATGAS code identified in paragraph (a)(3)(xiii) of this section, Bonneville will calculate the escalation rate using Bonneville's most current forecast of natural gas prices. The code CONSTANT in paragraph (a)(3)(iv) of this section indicates that no escalation to the Account will be made.

(5) Bonneville will base the costs of power products purchased from Bonneville on Bonneville's forecast of prices for its products.

(6) Bonneville will escalate the Public Purpose Charge forward to the midpoint of the Exchange Period by the same rate of growth as total Contract System Load.

(7) If any of the escalators specified in paragraph (a) of this section are no longer available, Bonneville will designate a replacement source of such escalator(s) that, as near as possible, replicates the results produced by the prior escalator. If a replacement source is not available, Bonneville will use the INF escalation code identified in paragraph (a)(3)(xii) of this section as the replacement escalator.

(b) Calculation of sales for resale and power purchases.

(1) Long-term and intermediate-term sales for resale and power purchases. Bonneville will use the INF escalation code identified in paragraph (a)(3)(xii) of this section to escalate long-term and intermediate-term (as defined by the Commission) firm purchased power costs and long-term and intermediate-term sales for resale revenues.

(2) Short-term sales for resale and power purchases.

(i) The short-term purchases and short-term sales for resale for the Base Period will be used as the starting values. A Utility will be allowed to include new plant additions, and to use a utility-specific forecast for the price of purchased power and for the price of sales for resale in order to value purchased power expenses and sales for resale revenue to be included in the Exchange Period ASC.

(ii) Bonneville will use the following method to determine separate market prices to forecast short-term purchased power expenses and sales for resale revenues to calculate Exchange Period ASCs:

(A) The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three~~five~~ years of actual data (Base Period and prior two~~four~~ years).

(B) The midpoint between the Utility's average short-term purchased power price and the average short-term sales for resale price will be calculated for each of the years in paragraph (b)(2)(ii)(A) of this section.

(C) The percentage spread around the Utility's midpoint between the average short-term purchased power price and short-term sales for resale price will be calculated for each of the years identified in paragraph (b)(2)(ii)(A) of this section.

(D) A weighted average spread for the Utility's most recent five years of actual data (Base Period and prior two~~four~~ years) will be calculated. The following weighting scale will be used:

(1) Three~~Five~~ (3~~5~~) times Base Period spread.

(2) Two~~Four~~ (2~~4~~) times (Base Period minus 1) spread.

(3) One~~Three~~ (1~~3~~) time (Base Period minus 2) spread.

~~(4) Two (2) times (Base Period minus 3) spread.~~

~~(5) One (1) times (Base Period minus 4) spread.~~

(E) The Base Period midpoint calculated in paragraph (b)(2)(ii)(B) of this section will be escalated at the same rate as Bonneville's electric market price forecast.

(F) The weighted average spread calculated in paragraph (b)(2)(ii)(D) of this section will be applied to the escalated midpoint price calculated in paragraph (b)(2)(ii)(E) of this section to determine the purchased power price and sales for resale price to value purchased power expenses and sales for resale revenues to be included in the Exchange Period ASC.

(iii) The method described in paragraph (b)(2)(ii) of this section will be used to forecast 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.

(c) Major resource additions and reductions and materiality thresholds.

(1) 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. These changes, however, must meet the requirements of paragraph (c)(3) of this section and the materiality threshold described in paragraph (c)(4) of this section in order for Bonneville to allow an ASC to change. The ASC reflecting the major resource addition or reduction will be determined by Bonneville in the ASC Review Process during the Review Period.

(2) For major resource additions, the change to ASC will become effective when the resource begins commercial operation, or power is received under the purchased power contract. For major resource reductions, the change to ASC will become effective when the resource is sold, retired, or transferred.

(3) A major resource addition or reduction must be related to one or more of the following categories to be eligible for consideration as a major resource:

(i) Production or generating resource investments;

(ii) Long-term generating contracts;

(iii) Pollution control and environmental compliance investments relating to generating resources;

(iv) Hydroelectric relicensing costs and fees; and

(v) Plant rehabilitation investments.

(4) Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's Exchange Period ASC ~~within an Exchange Period~~ provided that the major resource addition or reduction ~~results~~ meets the following materiality threshold. ~~For a~~A resource that becomes operational after the Base Period, but prior to the publi-

cation of the Final ASC Report~~start of the Exchange period, but after the Base period~~, must result in a percentage change of 0.5 percent or greater in the utility's B~~b~~ase P~~p~~eriod ASC to be considered material. -During the Exchange P~~p~~eriod, the resource addition or reduction must result in a 2.5 percent or greater change in a Utility's Base Period ASC to be considered material. ~~Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.~~

(5) At the time the Utility submits its Appendix 1 filing, the Utility will provide its forecast of major resource additions or reductions and all associated costs. The forecast will cover the period from the end of the Base Period to the end of the Exchange Period.

(6) The forecast of major resource additions or reduction costs to be included in the Utility's Exchange Period ASC will be reviewed by Bonneville in the ASC Review Process that is conducted during the Review Period.

(7) All major resources included in an ASC calculation prior to the publication ~~f~~of the Final ASC Report~~start of the Exchange Period~~ will be projected forward to the midpoint of the Exchange Period.

(8) For each major resource addition or reduction that is forecasted to occur during the Exchange Period, Bonneville will calculate the difference in ASC between the ASC without the major resource addition or reduction and the ASC with the major resource addition or reduction (ASC delta) at the midpoint of the Exchange Period.

(9) Once the major resource addition or reduction becomes effective, as determined by paragraph (c)(2) of this section, Bonneville will add the ASC delta to the Utility's existing ASC to determine its new ASC.

(10) Bonneville will escalate the components of the resource costs used to serve NLSLs to the Exchange Period using the following steps:

(i) Escalate the components of the fully allocated resource costs to the Exchange Period.

(ii) Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

(iii) The cost to serve NLSLs may change when the ASC changes due to resource additions/retirements.

(iv) The Exchange Period NLSL load will equal the Base Period NLSL load.

(11) For purposes of calculating ratios with Distribution Plant, Bonneville will escalate the Base Period average per-MWh cost of Distribution Plant forward to the midpoint of the Exchange Period, and use the escalated average cost to determine the distribution-related cost of meeting load growth since the Base Period.

(12) Bonneville will escalate the cost of General Plant, Accounts 389 through 399.1, forward to the midpoint of the Exchange Period by calculating the ratio of each Account's value in the Base Period to the sum of Production, Transmission, and Distribution plant values in the Base Period, and then multiplying the Base Period ratio times the forecasted value for Production, Transmission, and Distribution plant.

(13) Confidentiality procedures regarding a Utility's major resource additions or reductions are contained in the ASC Rules of Procedure, Attachment B, ASC Confidentiality Rules.

(d) Forecasted Contract System Load and Exchange Load. All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss analysis as described in Endnote j~~e~~ of Appendix 1, with their Appendix 1 filings. The load forecast for Contract System Load and Exchange Load will start with the Base Period and extend through four (4) years after the Exchange Period. The load forecast for Contract System Load and Exchange Load will be provided on a monthly basis for the Exchange Period.

(e) Load growth not met by major resource additions. All forecast load growth not met by major resource additions will be met by purchased power at the forecasted utility-specific, short-term purchased power price.

(1) 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.

(2) In the event of major resource additions, forecast Load Growth will be met by the major resource(s). If the major resource is less than total forecast load growth, the unmet Load Growth will be met with electric market purchases priced at the Utility's forecast short-term purchased power price.

(3) In the event the power provided by a major resource exceeds the Utility's forecast Load Growth, the excess power will be used to reduce the Utility's short-term purchases. If short-term power purchases are reduced to zero, any remaining power will be sold as surplus power at the short-term sales for resale price as determined in paragraph (b) of this section.

(f) Changes to service territory. In the event a Utility forecasts that it will acquire a new service territory, or lose a portion of its existing service territory, and the gain or loss of that territory results in a 2.5 percent or greater change to the Utility's Base Period ASC, the Utility must file two Appendix 1 filings with Bonneville as follows:

(1) First, a Base Period ASC that does not reflect the acquisition or loss of service territory; and

(2) Second, a Base Period ASC that incorporates the following changes:

(i) A forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

(ii) A forecast of the increase or reduction in Contract System Cost associated with the acquisition or reduction of the service territory.

(iii) A forecast of capital and operating cost increases or reductions associated with the change in service territory.

(iv) A forecast of the changes in purchased power expenses, sales for resale revenues, and other debits or credits based on the changes in the service territory.

(3) Because the date of the actual change to the Utility's service territory could differ from the forecast date used to determine the ASC during the Review Period, Bonneville will not adjust the Utility's ASC until the change in service territory takes place.

(g) Filing of Appendix 1. Utilities must file an Appendix 1, including ASC information, by June 1 of each year, as required in § 301.3, for Bonneville's review and determination of a Base Period ASC. Utilities will file multiple, contingent, Base Period ASC filings to reflect changes to service territories as required in paragraph (f) of this section.

18 CFR § 301.6

§ 301.6 Changes in Average System Cost methodology.

(a) The Administrator, at his or her discretion, 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.

(b) The Administrator will not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, that is, one year after the then-existing ASC Methodology is adopted by Bonneville and approved by the Commission, through interim or final approval, whichever occurs first.

(c) The Administrator may, from time to time, issue interpretations of the ASC methodology. The Administrator also may modify the functionalization code of any Account to comply with the limitations identified in Sections 5(c)(7)(A)-(C) of the Northwest Power Act or to conform to Commission revisions to the Uniform System of Accounts.

18 CFR § 301.7

§ 301.7 Provisions for Public Customers

REP-participating Public Utilities will have the same ASCM provisions applicable as REP-participating IOUs and provide data equivalent to FERC Form 1.

18 CFR PT. 301, TBL. 1

Table 1--Functionalization and Escalation Codes

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| ***Schedule 1: Plant Investment/Rate Base*** | | | | | |
| **Intangible Plant:** | | | | | |
| Intangible Plant - Organization | 301 | DIST | | CONSTANT | |
| Intangible Plant - Franchises and Consents | 302 | DIRECT | PTD | CONSTANT | |
| Intangible Plant - Miscellaneous | 303 | DIRECT | DIST | CONSTANT | |
| **Production Plant:** | | | | | |
| Steam Production | 310-317 | PROD | | CONSTANT | |
| Nuclear Production | 320-326 | PROD | | CONSTANT | |
| Hydraulic Production | 330-337 | PROD | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Solar Production | 338.1-338.13 | PROD | | CONSTANT | |
| Wind Production | 338.20-338.34 | PROD | | CONSTANT | |
| Other Renewable Production | 339.1-339.13 | PROD | | CONSTANT | |
| Other Production | 340-347 | PROD | | CONSTANT | |
| **Transmission Plant:** | | | | | |
| Transmission Plant | 350-359.1 | TRANS | | CONSTANT | |
| **Distribution Plant:** | | | | | |
| Distribution Plant | 360-374 | DIST | | CD | |
| **Energy Storage Plant:** | | | | | |
| Energy Storage Plant | 387-387.12 | DIRECT~~PTD~~ | PTD | CONSTANT | k/ |
| **General Plant:** | | | | | |
| Land and Land Rights | 389 | PTD | | CONSTANT | |
| Structures and Improvements | 390 | PTD | | CONSTANT | |
| Furniture and Equipment | 391 | LABOR | | CONSTANT | |
| Transportation Equipment | 392 | TD | | CONSTANT | |
| Stores Equipment | 393 | PTD | | CONSTANT | |
| Tools, Shop and Garage Equipment | 394 | PTD | | CONSTANT | |
| Laboratory Equipment | 395 | PTD | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Power Operated Equipment | 396 | TD | | CONSTANT | |
| Computer Hardware | 397.1 | PTD | | CONSTANT | |
| Computer Software | 397.2 | PTD | | CONSTANT | |
| Communication Equipment | 397.3 | PTD | | CONSTANT | |
| Miscellaneous Equipment | 398 | PTD | | CONSTANT | |
| Other Tangible Property | 399 | DIRECT | PTD | CONSTANT | |
| Asset Retirement Costs for General Plant | 399.1 | PTD | | CONSTANT | |
| **Depreciation Reserve:** | | | | | |
| Steam Production Plant | 108 | PROD | | CONSTANT | |
| Nuclear Production Plant | 108 | PROD | | CONSTANT | |
| Hydraulic Production Plant | 108 | PROD | | CONSTANT | |
| Other Production Plant | 108 | PROD | | CONSTANT | |
| Transmission Plant | 108 | TRANS | | CONSTANT | |
| Distribution Plant | 108 | DIST | | CONSTANT | |
| General Plant | 108 | GP | | CONSTANT | |
| Amortization of Intangible Plant - Account 301 | 111 | DIST | | CONSTANT | |
| Amortization of Intangible Plant - Account 302 | 111 | DIRECT | PTD | CONSTANT | |
| Amortization of Intangible | 111 | DIRECT | DIST | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Plant - Account 303 | | | | | |
| | | | | | |
| Amortization of Plant Held for Future Use | 111 | DIST | | CONSTANT | |
| Capital Lease - Common Plant | 108 | DIRECT | | CONSTANT | |
| | | | | | |
| In-Service: Depreciation of Common Plant | 108 | DIRECT | | CONSTANT | |
| Amortization of Other Utility Plant | 108 | DIRECT | DIST | CONSTANT | |
| Amortization of Acquisition Adjustments | 115 | DIRECT | | CONSTANT | |
| | | | | | |
| **Cash Working Capital:** | | | | | a/ |
| (Utility Plant) Held For Future Use | 105 | DIST | | CONSTANT | |
| (Utility Plant) Completed Construction - Not Classified | 106 | PTD | | CONSTANT | |
| Nuclear Fuel | 120.1-120.6 | PROD | | NFUEL | |
| Construction Work in Progress (CWIP) | 107&120.1 | DIST | | CONSTANT | |
| Common Plant | 356 | DIRECT | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Acquisition Adjustments (Electric) | 114 | DIRECT | DIST | CONSTANT | |
| **Other Property and Investments:** | | | | | |
| Investment in Associated Companies | 123 | DIRECT | DIST | CONSTANT | |
| Investment in Subsidiary Companies | 123.1 | DIRECT | DIST | CONSTANT | |
| Other Investment | 124 | DIST | | CONSTANT | |
| Long-Term Portion of Derivative Assets | 175 | DIST | | CONSTANT | |
| Long-Term Portion of Derivative Assets - Hedges | 176 | DIST | | CONSTANT | |
| **Current and Accrued Assets:** | | | | | |
| Fuel Stock | 151 | PROD | | COAL | |
| Fuel Stock Expenses Undistributed | 152 | PROD | | CONSTANT | |
| Plant Materials and Operating Supplies | 154 | PTD | | INF | |
| Merchandise (Major Only) | 155 | DIST | | INF | |
| Other Materials and Supplies (Major only) | 156 | DIST | | INF | |
| Allowance Inventory | 158.1 | PROD | | CONSTANT | |
| Allowances Withheld | 158.2 | PROD | | CONSTANT | |

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Stores Expense Undistributed | 163 | PTD | | INF | |
| Prepayments | 165 | PTD | | CONSTANT | |
| Derivative Instrument Assets | 175 | DIST | | CONSTANT | |
| Less: Long-Term Portion of Derivative Assets | 175 | DIST | | CONSTANT | |
| Derivative Instrument Assets – Hedges | 176 | DIST | | CONSTANT | |
| Less: Long-Term Portion of Derivative Assets - Hedges | 176 | DIST | | CONSTANT | |
| **Deferred Debits:** | | | | | |
| Unamortized Debt Expenses | 181 | PTDG | | CONSTANT | |
| Extraordinary Property Loss-es | 182.1 | DIRECT | DIST | CONSTANT | |
| Unrecovered Plant and Regu-latory Study Costs | 182.2 | DIRECT | DIST | CONSTANT | |
| Other Regulatory Assets | 182.3 | DIRECT | DIST | CONSTANT | |
| Preliminary Survey and In-vestigation Charges (Major only) | 183 | DIST | | CONSTANT | |
| | | | | | |
| | | | | | |
| Clearing Accounts | 184 | DIST | | CONSTANT | |

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Temporary Facilities | 185 | PTDG | | CONSTANT | |
| Miscellaneous Deferred Debits | 186 | DIRECT | DIST | CONSTANT | |
| Deferred Losses from Disposition of Utility Plant | 187 | DIRECT | DIST | CONSTANT | |
| Research, Development, and Demonstration Expenditures | 188 | DIST | | CONSTANT | |
| Unamortized Loss on Reacquired Debt | 189 | PTDG | | CONSTANT | |
| Accumulated Deferred Income Taxes | 190 | DIST | | CONSTANT | |
| **Liabilities and Other Credits (Comparative Balance Sheet):** | | | | | |
| Derivative Instrument Liabilities | 244 | DIST | | CONSTANT | |
| Less: Long-Term Portion of Derivative Instrument Liabilities | 244 | DIST | | CONSTANT | |
| Derivative Instrument Liabilities – Hedges | 245 | DIST | | CONSTANT | |
| Less: Long-Term Portion of Derivative Inst Liabilities–Hedges | 245 | DIST | | CONSTANT | |
| Customer Advances for Construction | 252 | DIST | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Other Deferred Credits | 253 | DIRECT | DIST | CONSTANT | |
| Other Regulatory Liabilities | 254 | DIRECT | DIST | CONSTANT | |
| Accumulated Deferred Investment Tax Credits | 255 | DIST | | CONSTANT | |
| Deferred Gains from Disposition of Utility Plant | 256 | DIRECT | DIST | CONSTANT | |
| Unamortized Gain on Reacquired Debt | 257 | PTDG | | CONSTANT | |
| Accumulated Deferred Income Taxes-Accel. Amort. Property | 281 | DIST | | CONSTANT | |
| Accumulated Deferred Income Taxes-Property | 282 | DIST | | CONSTANT | |
| Accumulated Deferred Income Taxes-Other | 283 | DIST | | CONSTANT | |
| ***Schedule 2: Capital Structure and Rate of Return*** | | | | | h/ |
| ***Schedule 3: Expenses*** | | | | | |
| **Power Production Expenses:** | | | | | |
| **Steam Power Generation** | | | | | |
| Steam Power – Fuel | 501 | PROD | | COAL | |
| Steam Power - Operations (Excluding 501 - Fuel) | 500-509 | PROD | | SOPS | |
| Steam Power – Maintenance | 510-515 | PROD | | SMN | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| **Nuclear Power Generation** | | | | | |
| Nuclear – Fuel | 518 | PROD | | NFUEL | |
| Nuclear - Operation ( Excluding 518 - Fuel) | 517-525 | PROD | | NOPS | |
| Nuclear – Maintenance | 528-532 | PROD | | NMN | |
| **Hydraulic Power Generation** | | | | | |
| Hydraulic – Operation | 535-540.1 | PROD | | HOPS | |
| Hydraulic – Maintenance | 541-545.1 | PROD | | HMN | |
| **Other Power Generation** | | | | | |
| Other Power – Fuel | 547 | PROD | | NATGAS | |
| Other Power - Operations (Excluding 547 - Fuel) | 546-550.1 | PROD | | OOPS | |
| Other Power – Maintenance | 551-554.1 | PROD | | OMN | |
| **Other Power Supply Expenses** | | | | | |
| Purchased Power (long term and intermediate term) | 555 | PROD | | INF | |
| Purchased Power (short term) | 555 | PROD | | See section 301.5.b.2 | |
| Power Purchased for Storage Operations | 555.1 | PTD | | CONSTANT | |
| System Control and Load Dispatching | 556 | PROD | | CONSTANT | |

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Other Expenses | 557 | PROD | | CONSTANT | |
| Energy Storage Expenses: Operation | 577.1-577.5 | DIRECT~~PTD~~ | PTD | CONSTANT | k/ |
| Energy Storage Expenses: Maintenance | 578.1-578.7 | DIRECT~~PTD~~ | PTD | CONSTANT | k/ |
| Public Purpose Charges | | DIRECT | | See Section 301.5.a.6 | b/ |
| **Transmission Expenses:** | | | | | |
| Transmission of Electricity by Others (Wheeling) | 565 | PROD | | INF | c/ |
| Total Operations less Wheeling | 560-567.1 | TRANS | | TOPS | |
| Total Maintenance | 568-574 | TRANS | | TMN | |
| **Distribution Expense:** | | | | | |
| Total Operations | 580-589 | DIST | | DOPS | |
| Total Maintenance | 590-598 | DIST | | DMN | |
| **Customer and Sales Expenses:** | | | | | |
| Total Customer Accounts | 901-905 | DIST | | CACNT | |
| Supervision | 907 | DIST | | CSERV | |
| Customer assistance expenses (Major only) | 908 | DIST | | CSERV | d/ |
| Customer Service and Infor- | 909-910 | DIST | | CSALES | |

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| mation | | | | | |
| Total Sales Expense | 911-917 | DIST | | CSALES | |
| **Administration and General Expense:** | | | | | |
| **Operation** | | | | | |
| Administration and General Salaries | 920 | LABOR | | A&G | |
| Office Supplies & Expenses | 921 | LABOR | | A&G | |
| (Less) Administration Expenses Transferred - Credit | 922 | LABOR | | A&G | |
| Outside Services Employed | 923 | LABOR | | A&G | |
| Property Insurance | 924 | PTDG | | A&G | |
| Injuries and Damages | 925 | DIST | | A&G | e/ |
| Commission-Approved Injuries and Damages | | LABOR | | CONSTANT | f/ |
| Employee Pensions & Benefits | 926 | LABOR | | A&G | |
| Franchise Requirements | 927 | DIST | | A&G | |
| Regulatory Commission Expenses | 928 | DIST | | A&G | |
| (Less) Duplicate Charges - Credit | 929 | PTDG | | A&G | |
| General Advertising Expenses | 930.1 | DIST | | A&G | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Miscellaneous General Expenses | 930.2 | DIST | | A&G | |
| Rents | 931 | DIST | | A&G | |
| | | | | | |
| **Maintenance** | | | | | |
| Maintenance of General Plant | 935 | GPM | | A&G | |
| **Depreciation and Amortization:** | | | | | |
| Amortization of Intangible Plant - Account 301 | 404 | DIST | | CONSTANT | |
| Amortization of Intangible Plant - Account 302 | 404 | DIRECT | PTD | CONSTANT | |
| Amortization of Intangible Plant - Account 303 | 404 | DIRECT | DIST | CONSTANT | |
| Steam Production Plant | 403 | PROD | | CONSTANT | |
| Nuclear Production Plant | 403 | PROD | | CONSTANT | |
| Hydraulic Production Plant - Conventional | 403 | PROD | | CONSTANT | |
| Hydraulic Production Plant - Pumped Storage | 403 | PROD | | CONSTANT | |
| Other Production Plant | 403 | PROD | | CONSTANT | |
| Transmission Plant | 403 | TRANS | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Distribution Plant | 403 | DIST | | CONSTANT | |
| General Plant | 403 | GP | | CONSTANT | |
| Common Plant – Electric | 403 & 404 | DIRECT | | CONSTANT | |
| Depreciation Expense for Asset Retirement Costs | 403.1 | DIRECT | | CONSTANT | |
| Amortization of Limited Term Electric Plant | 404 | DIRECT | | CONSTANT | |
| Amortization of Plant Acquisition Adjustments (Electric) | 406 | DIRECT | | CONSTANT | |
| ***Schedule 3A: Taxes*** | | | | | |
| **FEDERAL:** | | | | | |
| Income Tax (Included on Schedule 2) | 409.1 | DIST | | CONSTANT | |
| Employment Tax | 408.1 | LABOR | | WAGES | |
| Other Federal Taxes | 408.1 | DIST | | CONSTANT | |
| **STATE AND OTHER:** | | | | | |
| Property (or In-Lieu) | 408.1 | PTDG | | CONSTANT | |
| Unemployment | 408.1 | LABOR | | WAGES | |
| State Income, B&O, etc. | 409.1 | DIST | | CONSTANT | |
| Franchise Fees | 408.1 | DIST | | CONSTANT | |
| Regulatory Commission | 408.1 | DIST | | CONSTANT | |

# Table 1: Functionalization and Escalation Codes

| **BONNEVILLE POWER ADMINISTRATION**<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| City/Municipal | 408.1 | DIST | | CONSTANT | |
| Other | 408.1 | DIST | | CONSTANT | |
| ***Schedule 3B: Other Included Items*** | | | | | |
| **Other Included Items:** | | | | | |
| Regulatory Credits | 407.4 | DIRECT | PROD | CONSTANT | |
| Less: Regulatory Debits | 407.3 | DIRECT | DIST | CONSTANT | |
| Gain from Disposition of Utility Plant | 411.6 | DIRECT | PROD | CONSTANT | |
| Loss from Disposition of Utility Plant | 411.7 | DIRECT | DIST | CONSTANT | |
| Gain from Disposition of Allowances | 411.8 | PROD | | CONSTANT | |
| Loss from Disposition of Allowances | 411.9 | PROD | | CONSTANT | |
| Miscellaneous Nonoperating Income | 421 | DIRECT | PROD | CONSTANT | |
| **Sale for Resale:** | | | | | |
| Sales for Resale (long term and intermediate term) | 447 | PROD | | INF | g/ |
| Sales for Resale (short term) | 447 | PROD | | See section 301.5.b.2 | g/ |
| Transmission for Sales for Resale | | | DIRECT | | g/ |

# Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| **Other Revenues:** | | | | | |
| Forfeited Discounts | 450 | DIST | | CONSTANT | |
| Miscellaneous Service Revenues | 451 | DIST | | CONSTANT | |
| Sales of Water and Water Power | 453 | PROD | | CONSTANT | |
| Rent from Electric Property | 454 | TD | | CONSTANT | |
| Interdepartmental Rents | 455 | DIST | | CONSTANT | |
| Other Electric Revenues | 456 | DIRECT | PROD | CONSTANT | |
| Revenues from Transmission of Electricity of Others | 456.1 | TRANS | | CONSTANT | |
| ***Schedule 4: Average System Cost*** | | | | | i/ & j/ |
| ***Labor Ratios*** | | | | | |
| **Labor Ratio Input:** | | | | | |
| Production | | PROD | | WAGES | |
| Transmission | | TRANS | | WAGES | |
| Distribution | | DIST | | WAGES | |
| Customer Accounts | | DIST | | WAGES | |
| Customer Service and Informational | | DIST | | WAGES | |
| Sales | | DIST | | WAGES | |

## Table 1: Functionalization and Escalation Codes

| BONNEVILLE POWER ADMINISTRATION<br>2026 Average System Cost Methodology<br>Functionalization and Escalation Codes | | | | | |
|---|---|---|---|---|---|
| **Account Description** | **Acct No.** | **Functionalization** | | **Escalation Codes** | **Endnote** |
| | | **Default** | **Optional** | | |
| Administrative & General | | PTD | | WAGES | |

18 CFR PT. 301, Table 1 Endnotes

a/ See section 301.4r

b/ See Section 301.4.t

c/ See section 301.4.x.1

d/ See section 301.4.s

e/ See section 301.4.w

f/ See section 301.4.w.1

g/ See section 301.4.x.2

h/ See section 301.4.o

i/ See section 301.4.p

j/ See section 301.4.n

k/ See section 301.4.v

18 CFR PT. 301, APP. 1

Appendix 1 to Part 301--ASC Utility Filing Template

Bonneville Power Administration

# ASC Methodology Part II

BPA Rules of Procedure for ASCs

**DEPARTMENT OF ENERGY**

**BONNEVILLE POWER ADMINISTRATION**

**RULES OF PROCEDURE FOR**

**BPA'S ASC REVIEW PROCESSES**

XX 2026

~~ASC REVIEW RULES OF PROCEDURE~~

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## SECTION 1. SUMMARY

Section 5(c)(7) of the Northwest Power Act requires the Bonneville Power Administration (BPA) to develop a methodology for determining a Utility's average system cost (ASC) for the purpose of selling power to BPA under the Residential Exchange Program, 16 U.S.C. § 839c(c). 16 U.S.C. § 839c(c)(7). Such methodology is subject to "review and approval" by the Federal Energy Regulatory Commission (FERC or Commission). 16 U.S.C. § 839c(c)(7).

The purpose of this document is to provide these procedures. Unless otherwise stated, capitalized terms shall have the meaning established by 18 C.F.R. § 301.2.

## SECTION 2. FILING PROCEDURES

### 2.1 ASC Filing Requirements

The Utility shall electronically submit an ASC Filing with BPA by June 1, or such other date as determined by BPA, of each year. Base Period ASC Filings occur as part of an ASC Review Process to determine a Utility's ASC for the applicable Exchange Period. Informational ASC Filings occur in all other years. An ASC Filing consists of the workbook/models, documents and other materials, as described in this section 2.1.

#### 2.1.1 Base Period ASC Filings:

The Utility shall submit a Base Period ASC Filing in years when BPA conducts an ASC Review Process to determine a Utility's ASC for the applicable Exchange Period. ASCs will change during the Exchange Period only for reasons provided in 18 C.F.R. § 301.5.

2.1.1.1 The Base Period ASC Filing shall include:

(a) a fully populated Appendix 1 workbook with source data from the Utility's FERC Form 1 applicable to the ASC Filing;

(b) supporting documentation, studies, and analysis used to prepare the Appendix 1;

(c) the Utility's pre-run Forecast Model;

(d) a separate variance analysis, which includes the accounts (amounts and functionalization) from Appendix 1 Schedules: 1, 3, 3A, 3B, and Load Forecast tab for the current Base Period ASC Filing Appendix 1 and the prior Base Period ASC Filing final Appendix 1 inputs;

(e) a signed Attachment A - Senior Financial Officer Attestation, signed by the Utility's senior financial officer attesting that the ASC Filing complies with FERC's Uniform System of Accounts, the ASC Methodology, and Generally Accepted Accounting P

(f) rinciples, and is consistent with applicable orders and policies of the Utility's Regulatory Body;

(g) and applicable participation forms: Petition to Intervene and Confidentiality Agreement.

### 2.1.2 Informational ASC Filings:

In years when BPA is not conducting a Base Period ASC Review Process, the Utility shall submit an Informational ASC Filing that includes information outlined in section 2.1.1.1 (a), (b) and (d). Informational ASC Filings will not affect the Utility's ASC.

## 2.2 Failure to Submit an ASC Filing and Patently Deficient ASC Filing

### 2.2.1 Failure to Submit an ASC Filing

If a Utility fails to timely submit its ASC Filing and fails to cure the problem within the Period to Cure provided in section 2.2.3 below, BPA will deem the Utility's ASC equal to the PF Exchange Rate.

### 2.2.2 Filing a Patently Deficient ASC Filing

If a Utility submits an ASC Filing and it is patently deficient as determined by BPA, and the Period to Cure as described in section 2.2.3 below has expired, BPA will deem the Utility's ASC equal to the PF Exchange Rate.

2.2.3 **Period to Cure**

If a Utility fails to timely submit an ASC Filing, or if it submits an ASC Filing that BPA determines is patently deficient, BPA shall provide such Utility with notice and a period of seven (7) calendar days within which to file a sufficient ASC Filing. In the event the Utility fails to do so, or if BPA determines such new ASC Filing is also patently deficient BPA will deem the Utility's ASC equal to the PF Exchange Rate.

### 2.3 Submittal of Base Period ASC Filing and Notice of ASC Review Process

2.3.1 A Utility shall electronically submit a Base Period ASC Filing to BPA's secure REP website, or such other method as determined by BPA. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

2.3.2 BPA shall provide public notice of the right to file a petition to intervene in BPA's ASC Review Process.

## SECTION 3. ASC REVIEW PROCESS

The following procedures apply during an ASC Review Process. These procedures do not apply to Informational ASC Filings made outside of an ASC Review Process. Unless otherwise provided by these rules, deadlines end at 5 p.m., Pacific Prevailing Time, of the due date. Due dates that land on a weekend or federal holiday shall be due the following business day.

### 3.1 Interventions

3.1.1 The Utility that submitted an ASC Filing is automatically a party to its own ASC Review Process.

3.1.2 Any Regional Power Sales Customer or state utility Regulatory Body who submits a petition to intervene by the established deadline will be granted party status for an ASC review process.

3.1.3 Other interested parties may submit a petition to intervene and BPA shall grant party status at BPA's discretion. BPA will grant or deny petitions to intervene within seven calendar days after the deadline for filing such petitions.

3.1.4 Petitions to intervene must be filed for each respective ASC Review Process for a party to comment on such individual proceedings. The petitions must be uploaded to BPA's secure REP website in the folder designated by BPA. Petitions to intervene must state with particularity the petitioner's interest in the ASC Review Process and must include all ASC dockets in which the petitioner intends to intervene.

3.1.5 If the petitioner intends to review Confidential Information, the petitioner must file a populated Confidentiality Agreement pursuant to the ASC Confidentiality Rules in Attachment B by the deadline specified in the ASC Review Schedule.

## 3.2 Review of Utility's ASC

3.2.1 Each ASC Filing shall be reviewed by BPA and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the ASC Filing complies with the requirements of this Methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each ASC Filing shall be reviewed by B

PA to

determine whether the Contract System Load used by the Utility is an appropriate load for purposes of the Utility's ASC computation.

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. BPA shall not be obligated to pay REP benefits based on an ASC different than the ASC based on Contract System Costs

and Contract System Load as determined by BPA; provided that if a final order of the Commission or a reviewing court rejects BPA's ASC determinati
on, then the ASC payable by BPA shall be the ASC as revised by BPA on remand.

### 3.3 Discovery

3.3.1 BPA and parties shall electronically file data requests to the Utility and BPA via BPA's Secure REP website. BPA will make data requests available to all parties, subject to confidentiality rules. Each Utility shall respond to requests for information relevant to that Utility's ASC Filing. The responses should be addressed to the requestor and BPA. BPA will post responses on BPA's Secure REP website. The furnishing of proprietary or Confidential Information to parties may be made contingent on th
e gra
nting of proper safeguards to prevent unauthorized use or disclosure.

3.3.2 The responding Utility shall respond to each data request within ten calendar days. If a Utility objects to a data request, the party submitting the data request may respond to the objection within four calendar days. After the response to the objection is received, or the four days to respond has elapsed, BPA then has seven calendar days to issue a decision as to whether the Utility's objection is sustained or overruled. If the objection is overruled, the Utility must provide the data requested wit
hin t
hree calendar days after BPA's decision. If a Utility does not provide the requested data, BPA may, at its discretion, remove from Contract System Costs all costs or revenues associated with the data not provided.

3.3.3 Confidential Information requested in a data request shall be made available to a Qualified Person, as defined in BPA's ASC Confidentiality Rules, unless the disclosing party objects pursuant to section 5 of the ASC Confidentiality Rules.

### 3.4 ASC Review Process Clarification Workshops

BPA may commence clarification workshops on Base Period ASC Filings in accordance with the ASC Review Process schedule. Utilities submitting an ASC Filing shall make available staff or agents with sufficient knowledge to provide clarification and answers in response to questions by BPA and other parties to the proceeding. The purpose of the clarification workshop is to clarify data, work papers, supporting documentation, and assumptions used to prepare the Appendix 1.

## 3.5 Issue Lists

3.5.1 BPA and parties may electronically file an issue list identifying contested elements of a Utility's ASC Filing and the basis for the parties' positions. Issue lists shall be filed to that Utility's ASC Review folder on BPA's Secure REP website. BPA will make the issue lists available to all parties.

3.5.2 Each filing Utility will electronically file a response to issue lists regarding its ASC Filing. BPA and other parties also may file responses to issue lists.

3.5.3 A workshop may be held to discuss and attempt to resolve issues raised by parties through their issue lists.

## 3.6 Oral Argument

3.6.1 Requests for oral argument before the Administrator or his/her designee must be submitted in writing to BPA by the date designated in the ASC review process schedule. Such requests shall contain a statement setting forth reasons why the party believes oral argument is necessary.

3.6.2 BPA, at its discretion, may grant or deny any request for oral argument.

3.6.3 In the event a request for oral argument is granted, the requesting party shall present its argument first. Responding parties shall present their arguments thereafter. The Administrator or his/her designee, at his/her discretion, may provide an opportunity for the requesting party to reply.

### 3.7 ASC Reports

#### 3.7.1 **Draft ASC Report**

3.7.1.1 BPA will publish for comment and electronically serve Draft Utility ASC Reports on all parties. The Draft ASC Reports will contain BPA's preliminary analyses and decisions on all contested issues raised in each ASC review process.

3.7.1.2 The Utility and parties may file comments on a Draft Utility ASC Report. The Utility and parties must specifically identify the decision or statement from the Draft ASC Report that is being addressed in the comments. Comments that contain generic statements regarding a Utility's ASC may not be considered by BPA.

3.7.1.3 A party's failure to raise an issue in comments on the Draft Utility ASC Reports waives that issue on appeal.

#### 3.7.2 **Final ASC Report**

The BPA Administrator will issue Final ASC Reports in conjunction with the publication of the Final Rate Case Proposal. The Final ASC Report will include BPA's final determination of the Utility's ASC.

## SECTION 4. ASC REVIEW PROCESS SCHEDULE

The Base Period ASC Filing shall be subject to the following schedule:

### 4.1 ASC Review Process

The ASC Review Process commences on June 1 of the Review Period, or such other date as may be established by BPA (Day 1). -BPA will provide prior notice of the commencement date and conduct a kickoff workshop preceding the ASC Review

Process. BPA will review all Utilities' ASCs concurrently in a public process. ~~A kick-off workshop will preceed the ASC Review Process.~~

### 4.2 ASC Review Schedule

The days identified below are generic and intended to illustrate a timeline that is representative of the ASC review process. Unless specified, the days listed represent calendar days. Each spring prior to a Review Period, BPA will post on its ASCM website (https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings or its successor), a detailed schedule, accommodating applicable holidays and weekends, that shall be the official schedule for that Review Period. Deadlines end at 5 p.m., Pacific Prevailing Time, of the due date.

| | |
|---|---|
| 1. **Day 1**: | Utility posts its filings to BPA's "Secure REP" website. Access to such information shall be subject to any confidentiality rules and requirements established by BPA. |
| 2. **Day 8**: | Deadline to file Utility-specific petitions to intervene with BPA for the Review Process. |
| 3. **Day 10**: | BPA grants or denies petitions to intervene. |
| 4. **Day 11-60**: | Parties allowed to submit Data Requests. |
| 5. **Day TBD**: | BPA will commence workshops on all Base Period ASC Filings based on the specific schedules. |
| 6. **Day 81**: | BPA's and parties' Issue Lists due. |
| 7. **Day 95**: | Utilities', BPA's, and parties' response(s) to Issues Lists due. |
| 8. **Day 101**: | A workshop to resolve issues raised by parties through their issues lists. |
| 9. **Day 165**: | Draft Utility ASC Reports issued. |
| 10. **Day 227**: | Requests for oral argument before the Administrator or his/her designee due. |
| 11. **Day 232**: | BPA grants or denies requests for oral argument. |
| 12. **Day 241**: | Oral argument. |

| | |
|---|---|
| 13. **Day 270**: | Comments on the Draft Utility ASC Reports due. |
| 14. **Day TBD**: | Final Utility ASC Reports issued in conjunction with the publication of the Final Rate Case Proposal. |

## SECTION 5. ACCESS TO FILING UTILITY'S DATA IN RETAIL RATE PROCEEDINGS

**5.1** BPA may petition to intervene in any retail rate proceeding for each Utility participating in the Residential Exchange Program for the purpose of obtaining information regarding costs or facts relevant to the determination of a Utility's ASC. BPA shall timely comply with the applicable intervening procedures of such retail rate proceeding. If the filing Utility denies BPA or any of its Regional Power Sales Customers the right to intervene in such retail rate proceeding BPA may deem the Utility's ASC equal

to the PF Exchange Rate for the applicable Exchange Period.

**5.2** Whenever a Utility submits a request to a Regulatory Body to commence a general rate case to change the retail rates charged to regional ratepayers, the Utility shall provide BPA with a written notice of such request. The Utility shall post such notification on BPA's Secure REP website in the folder designated by BPA. BPA will subsequently post the Utility's notice to the REP public website. The Utility's notice shall contain the following information:

5.2.1 the official name of the proceeding;

5.2.2 the docket number of the proceeding.

**Attachment A**

Senior Financial Officer Attestation

<<Customer's Name>>

Base Period Average System Cost Filing

For the Base Period Beginning ____________, 20XX

And Ending ____________, 20XX

I, ___________________________________, having reviewed the Base Period Average System Cost (ASC) Filing attached with this attestation, hereby certify that:

1. The Base Period ASC Filing has been prepared in accordance with Bonneville Power Administration's current ASC Methodology.

2. The Base Period ASC Filing excludes the costs associated with: (a) the cost of additional resources in an amount sufficient to serve any New Large Single Load (NLSL) after September 1, 1979; (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.

3. In support of item 2 above, <<Customer's Name>> performed a thorough review of its base period load by customer and confirms that <<Customer's Name>> is not serving any NLSL as defined in the *Bonneville Power Administration New Large Single Load Policy,* as may be amended or replaced, other than those NLSLs included in this Base Period ASC Filing, if any.

4. Based on my knowledge as <<Customer's Name>>'s Senior Financial Officer, the Base Period ASC Filing is based on <<Customer's Name>>'s audited financial statements, FERC Form 1 filings for IOUs and Annual and other financial information, and fairly presents in all material respects the operating costs of the utility for _________, 20XX through _________, 20XX.

5. Based on my knowledge as <<Customer's Name>>'s Senior Financial Officer, the Base Period ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Senior Financial Officer

<<Customer’s Name>>

Date:___________________

**Attachment B**

2026 ASC Confidentiality Rules

**1. SCOPE OF THESE RULES**

These Rules Governing the Disclosure of Confidential Information in BPA's Average System Cost Review Proceedings ("ASC Confidentiality Rules") govern the acquisition and use of "Confidential Information" in BPA's ASC review proceedings under the 2026 ASC Methodology, as amended or revised.

**2. DEFINITIONS**

Unless otherwise stated, capitalized terms shall have the meaning established by 18 C.F.R. § 301.2.

2.1 A "Qualified Person" is an individual who is:

2.1.1. An author(s) or originator(s) of the Confidential Information;

2.1.2. A BPA representative or staff person;

2.1.3. A person qualified pursuant to section 4.2.3 below. This includes parties and their employees.

**3. DESIGNATION OF CONFIDENTIAL INFORMATION**

3.1. A party providing Confidential Information shall designate such material as Confidential Information by placing the following legend on each page of the information:

**CONFIDENTIAL**

To the extent practicable, the party shall designate as Confidential Information only those portions of the document that are within the definition of Confidential Information.

3.2. For electronic files, the Utility should identify the Confidential Information with a generic file name that sufficiently describes the nature of the information without disclosing any Confidential Information.

3.3. A party may designate as Confidential Information any information previously provided by giving written notice to BPA and the other parties. Parties in possession of newly designated Confidential Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

## 4. TREATMENT OF CONFIDENTIAL INFORMATION PROVIDED AS PART OF A UTILITY'S ASC FILING

### 4.1. **Duty of Utility to Provide BPA with Confidential Information at Time of Utility's ASC Filing**

4.1.1. Confidential Information in an ASC Filing shall be submitted to BPA at the same time as non-confidential data and supporting documentation in accordance with this section.

4.1.2. The Utility shall upload Confidential Information separately from non-confidential information to BPA's secure REP website. The Utility must select the "confidential" option when uploading Confidential Information to ensure that it is viewed only by authorized parties.

4.1.3. Confidential Information submitted by a Utility shall be protected in accordance with these rules except that the name of the file containing Confidential Information will be visible on BPA's secure REP website.

### 4.2. Disclosure of Confidential Information Contained in Utility's ASC Filing

4.2.1. Except as provided in section 4.3, only persons designated as "Qualified Persons" shall have access to Confidential Information in a Utility's ASC Filing. Utilities will provide Qualified Persons access to Confidential Information at such time designated by BPA, unless the Utility objects as provided in section 4.3 below. BPA and the parties shall limit the use and dissemination of Confidential Information as required by section 6.

4.2.2. Qualified Persons may disclose Confidential Information to any other Qualified Person of the same party, unless the party desiring confidentiality protests as provided in section 4.3.

4.2.3. To become a Qualified Person under section 2.1.3 above, a person must:

4.2.3.1. Be a consultant, counsel, or employee of an entity that has received party status to the Utility's ASC Filing in the applicable ASC Review Process;

4.2.3.2. Have responsibility for reviewing the Utility's ASC Filing on behalf of such entity;

Execute and date the Confidentiality Agreement, appended as Attachment B-1, acknowledging that the person has read the ASC Confidentiality Rules and agrees to adhere to its terms; and

4.2.3.3. Provide their name, address, employer, and job title.

4.2.4. Parties requesting access to Confidential Information shall include a signed Confidentiality Agreement in the party's intervention. A party must file a revised Confidentiality Agreement with BPA and the Utility to add or remove a Qualified Person(s). The Utility may file pursuant to section 4.3 below to object to a party's request to add a new Qualified Person(s).

### 4.3. Objections to Disclosure of Confidential Information to Qualified Person

4.3.1. The Utility desiring to restrict a Qualified Person(s) access to Confidential Information provided in an ASC Filing must notify counsel for the party associated with the Qualified Person(s) within three (3) calendar days of receipt of the Confidentiality Agreement or by such other date designated by BPA. The Utility and the party(s) must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis.

4.3.2. If the dispute cannot be resolved informally, the Utility must file a motion with BPA within seven (7) calendar days of receipt of the party's Confidentiality Agreement or by such date designated by BPA. Such motion must describe in detail what steps the parties took to attempt to resolve the dispute, including selected redaction explored by the parties, and explain why such measures do not resolve the dispute. The party requesting access to Confidential Information shall have four (4) calendar days to respond to the Utility's objection.

4.3.3. Confidential Information will not be disclosed to a party's Qualified Person(s) until BPA renders a decision on the Utility's pending motion.

**4.4. Objections to the Designation of Confidential Information in Utility's ASC Filing**

~~4.4.1.1.~~

~~4.4.2.~~ If a party disagrees with a Utility's decision to designate information as Confidential Information, the party has three (3) calendar days from the date the Confidential Information is made available to the party's Qualified Person to notify the Utility of such objection. If the party has no Qualified Person(s) and has not otherwise filed a Confidentiality Agreement with BPA and the Utility, the three (3) calendar days shall start on the day the Confidential Information is uploaded to BPA's secure REP website.

~~4.4.3.~~4.4.1.

~~4.4.4.~~4.4.2. The party requesting the removal of the Confidential Information designation must confer with the Utility to determine if the objection can be resolved informally. If the party and the Utility are unable to resolve the issue, the party may file a motion stating its objection within seven (7) calendar days from the date the Confidential Information is made available to the party's Qualified Person, *or* if the party has no Qualified Person and has not filed a Confidentiality Agreement, seven (7) calendar days from the day the Confidential Information is uploaded to BPA's secure REP website. The party's motion must include the following:

~~4.4.4.1.~~4.4.2.1. Identify the contested information; and

~~4.4.4.1.1.~~ Assert and explain why the information does not fall within the definition of Confidential Information.

~~4.4.4.2.~~4.4.2.2. –

~~4.4.5.~~4.4.3. Upon receiving the party's motion, the Utility resisting disclosure shall have four (4) calendar days to respond. The Utility has the burden of showing that the challenged information falls within the definition of Confidential Information. If the Utility resisting disclosure does not respond within four (4) calendar days, the challenged information shall be removed from the protection of these rules.

~~4.4.6.~~4.4.4. The asserted Confidential Information shall not be disclosed pending a decision by BPA.

### 4.5. Use of Confidential Information in Issue Lists and Comments

4.5.1. Parties should not include Confidential Information in Issue Lists or Comments unless reference to such Confidential Information is essential to the issue or argument being made by the party. If reference to Confidential Information is necessary, the party shall separate from all other Issue Lists or Comments the Issue List or Comment that contains such Confidential Information.

4.5.2. After separating such material, the party shall upload the Comment or Issue List that contains Confidential Information as a "confidential" document on BPA's secure REP website. The party should designate BPA, the Utility, and the party (if different than the Utility) that provided the Confidential Information referenced in the Issue List or Comment as authorized persons to review the document.

## 5. TREATMENT OF CONFIDENTIAL INFORMATION REQUESTED IN DISCOVERY

~~5.1.~~ Confidential Information requested in a request for data under BPA's ASC Rules of Procedure shall be made available to a Qualified Person *unless* the disclosing party objects pursuant to this section.

~~5.2.~~5.1. –

~~5.3.~~5.2. The party desiring to restrict the Qualified Person(s) from obtaining Confidential Information in a data request must notify counsel for the party associated with the Qualified Person(s) within three (3) calendar days of receipt of the data request. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis.

5.3 If the dispute cannot be resolved informally, the party objecting to the data request must file a motion with BPA within ten (10) calendar days of receipt of the data request. Such motion must describe in detail what steps the parties took to attempt to resolve the dispute, including selected redaction explored by the parties, and explain why such measures do not resolve the dispute. The party requesting access to Confidential Information shall have four (4) calendar days to respond to the Utility's objection~~e~~

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5.4 ~~tion.~~

The objecting party may withhold contested Confidential Information until BPA renders a decision on the party's pending motion.

5.5

Notwithstanding any of the foregoing, no party may request Confidential Information obtained in a data request from another party. For example, if party X receives Confidential Information from a Utility through a data request, party Y may not submit a data request to party X requesting the same Confidential Information. In this example, party Y must submit a data request directly to the Utility to obtain the Confidential Information.

## 6. PRESERVATION OF CONFIDENTIALITY

6.1. All persons provided access to Confidential Information by reason of the ASC Confidentiality Rules shall not use or disclose the Confidential Information for any purpose other than preparation for and participation in the relevant ASC Review Process, and shall take all reasonable precautions to keep the Confidential Information secure. *Disclosure of Confidential Information for purposes of business competition is strictly prohibited.*

6.2. Qualified Persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation for, and participation in, the relevant ASC Review Process. Qualified Persons may disclose Confidential Information only to other Qualified Persons associated with the same party.

6.3. If a party violates the ASC Confidentiality Rules, BPA may take remedial action against such party, including, but not limited to, denying such party access to Confidential Information in the current or future ASC Review Process(es), dismissing or denying the party's intervention in the current or future ASC Review Process(es), or such other action that BPA deems necessary or appropriate.

6.4. BPA shall notify the party that provided Confidential Information as soon as practicable of any request received under the Freedom of Information Act (FOIA), or under any other Federal law or judicial or administrative order, for any Confidential Information. BPA shall only release such Confidential Information to comply with the FOIA or if required by any other Federal law or judicial or administrative order.

6.5. Any party in possession of Confidential Information shall notify the party that provided the Confidential Information as soon as practicable of any request received pursuant to a judicial or administrative order, or applicable law, for any Confidential Information. Confidential Information shall only be released if necessary to comply with such judicial or administrative order, or if required by applicable law.

## 7. DURATION OF PROTECTION

BPA shall preserve the confidentiality of Confidential Information for a period of five (5) years from the date of the final order in the relevant docket, unless extended by BPA at the request of the party desiring confidentiality.

## 8. DESTRUCTION AFTER PROCEEDING

Parties' counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents, whether electronic or hard copy, containing Confidential Information to the extent reasonably necessary to maintain a file for the relevant ASC Review Process or to comply with requirements imposed by another governmental agency, judicial order, or applicable law. The information retained may not be disclosed to any person other than a Qualified Person of the same party. Any person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party requesting confidentiality within ninety (90) days after final resolution of the relevant proceeding unless the party requesting confidentiality consent, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to BPA.

## 9. ADDITIONAL PROTECTIONS

9.1. A party desiring additional protections not otherwise afforded by these rules may file a motion with BPA requesting such additional protections. The motion shall state:

9.1.1. The parties and persons involved;

9.1.2. The exact nature of the information involved;

9.1.3. The exact nature of the relief requested;

9.1.4. The specific reasons the requested relief is necessary; and

9.1.5. A detailed description of the steps the parties have taken to attempt to resolve the dispute, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

9.2. Objection to such additional protections must be filed within four (4) calendar days following receipt of the party's motion.

9.3. BPA shall determine whether such additional protections are necessary for the relevant ASC Review Process.

**ATTACHMENT B-1**

**CONFIDENTIALITY AGREEMENT**

Docket Nos. [List all that apply]

## I. Confidentiality Agreement

This agreement governs the use of "Confidential Information" in the above-noted proceeding(s).

_______________________________(Party) agrees to be bound by the terms of the Rules Governing the Disclosure of Confidential Information in BPA's Average System Cost Review Process.

By: ______________________________ ______________________________

Signature Date

______________________________ ______________________________

Print Name Title

Persons Qualified Pursuant to Sections 2.1.3 and 4.2.3

I have read the Rules Governing the Disclosure of Confidential Information in BPA's Average System Cost Review Process and agree to adhere to the terms of such rules.

By:

______________________________ ______________________________

Signature Date

______________________________ ______________________________

Print Name Title

______________________________ ______________________________

Employer Address

By:

______________________________ ______________________________

| | |
|---|---|
| Signature | Date |
| Print Name | Title |
| Employer | Address |

**CONFIDENTIALITY AGREEMENT**

*(Extra Signature Page)*

Docket Nos. [List all that apply]

~~*(Extra Signature Page)*~~

Persons Qualified Pursuant to Sections 2.1.3 and 4.2.3

I have read the Rules Governing the Disclosure of Confidential Information in BPA's Average System Cost Review Process and agree to adhere to the terms of such rules.

By:

| | |
|---|---|
| Signature | Date |
| Print Name | Title |
| Employer | Address |

By:

| | |
|---|---|
| Signature | Date |
| Print Name | Title |
| Employer | Address |

By:

| | |
|---|---|
| Signature | Date |
| Print Name | Title |

| | |
|---|---|
| Employer | Address |

Attachment 2
BPA Incremental ASCM Presentation
January 27, 2025


# Post-2028 Residential Exchange Program ASCM Informal Comments Workshop

## Tuesday, January 27, 2026

9:00 am – 12:00 pm

WebEx Only

POST 2028 REP

# January 27th Workshop Agenda

| Workshop Topics | Presenter(s) |
|---|---|
| Introductions, Agenda, and Schedule | Scott Winner |
| Informal Comment Discussion | Team |
| Transmission | Richard Greene |
| Account 925 / Injuries and Damages | Neal Gschwend |
| Energy Storage Plant | Neal Gschwend |
| Disallowed Costs | Richard Greene |
| Grab Bag | Team |
| Next Steps and Closeout | Scott Winner |

# Post-2028 REP Team

- Kim Thompson, REP Sponsor (VP of NW Requirements Marketing)
- Paulina Cornejo, REP Policy Lead
- Michael Edwards, REP Technical Lead
- Aimee Robinson, Economist
- Richard Greene, Legal Counsel
- Neal Gschwend, Legal Counsel
- Stephanie Adams, Rates and 7(b)(2) Lead
- Jonathan Ramse, Economist
- Daniel Fisher, Power Rates Manager
- Scott Winner, PSRF Supervisor

# Phase 2 Schedule Update

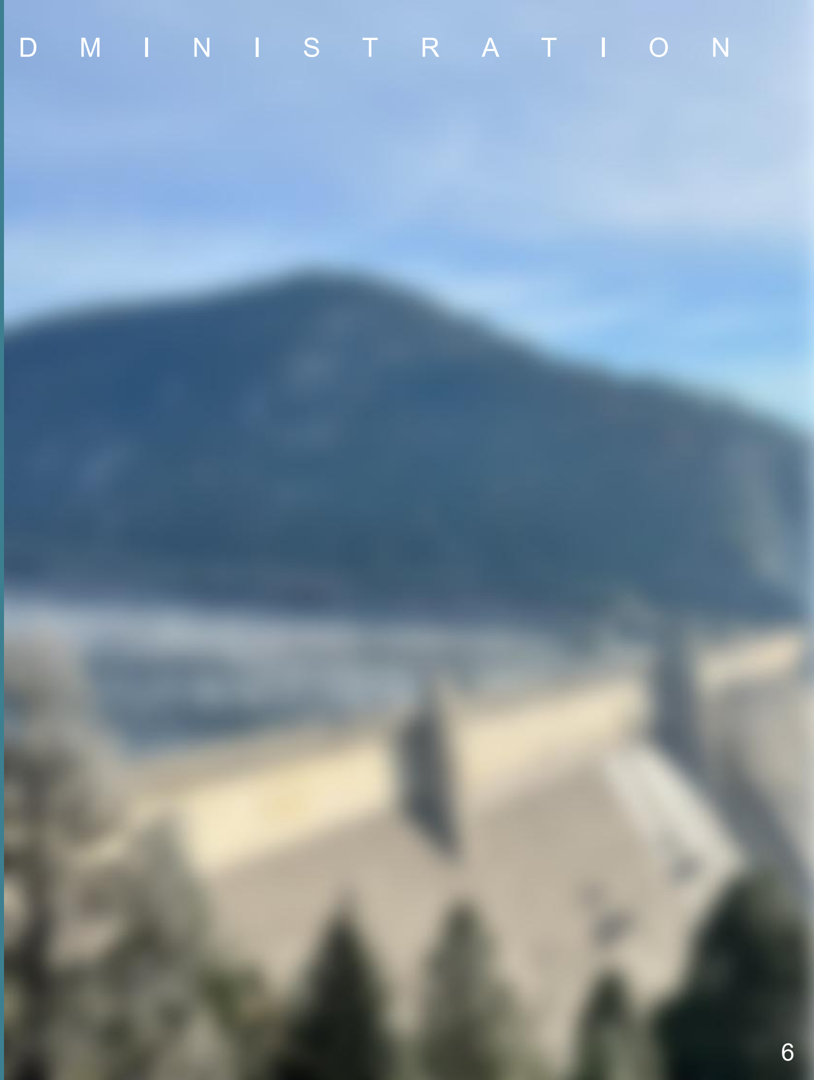
| Date | RPSA | ASCM |
| --- | --- | --- |
| Jan 21, Wed | **Comments due**, Full draft | **Comments due**, Preliminary draft |
| Jan 27, Tues | | **Workshop**, Preliminary comments |
| Feb 3, Tue | | **Post**, Incremental draft |
| Feb 10, Tues | | **Comments due**, Incremental |
| Feb 13, Fri | | **Workshop**, Incremental comments |
| Feb 20, Fri | | **Post**, Full draft |
| Mar 6, Fri (est.) | **ROD publication** | |
| Apr 2, Thurs | | **Comments due**, Full |
| May 22, Fri (est.) | | **ROD publication** |

# ASCM Informal Comment Workshop Topics

| Informal Comment Workshop: Jan. 27th | Incremental Comment Workshop 2: Feb. 13th | Full Draft ASCM Release: Feb. 20th | ROD release: May 22nd |
| --- | --- | --- | --- |
| • BPA Staff Proposals<br>• Prior discussion of topics<br>• Informal comments on topics | • Discussion of informal comments on incremental draft | • BPA releases full ASCM Draft for formal comment<br>• Regional parties submit comments through BPA Public Comments site: Make a Public Comment<br>• Comments due Apr. 2nd | • Final ROD released |

# Informal Comment Discussion

## Presenter – Team



POST 2028 REP

# BPA Staff Proposal – Transmission

- **Discussed at the Dec. 3, 2025 ASCM workshop, and introduced in Settlement Concept proposal.**
- **Draft ASCM text:**

  "(x) Transmission costs. Unless otherwise provided in paragraph (x) of this section, transmission costs are not included in ASC.

  (1) Transmission of Electricity by Others (Wheeling), Account 565. Costs included in Account 565 will be functionalized to Production and included in the Utility's ASC; provided however that costs included in Account 565 that are payable to an affiliated, associated, or subsidiary company will be functionalized to transmission and excluded from ASC.

  (2) Transmission (delivery) costs associated with Sales for Resale, Account 447. Costs included in Account 447 are assumed to include transmission costs associated with Sales for Resale. The Utility may record additional transmission costs not included in Sales for Resale in Schedule 3B in the line item "Transmission for Sales for Resales" and perform a Direct Analysis." [Part I, Section 301.4(x)]

# Informal Comments – Transmission

- **COUs:** "We are supportive of BPA's proposal to remove all transmission costs from the ASC except for those which are in principle as near to the transmission costs included in the PF rate as possible."
- **IOUs:** "…the IOUs strongly oppose BPA's transmission cost proposal. Excluding transmission costs harms IOU customers. The lack of access to BPA's resources, which are centrally located, results in the IOUs having to incur "additional" transmission beyond that incurred by COUs, who have more direct access to BPA federal power. Furthermore, this proposal creates a disincentive for utility investment in transmission, while creating an incentive for investment in BPA's transmission, as BPA is proposing to allow wheeling costs over its system."
- **WUTC:** "As Washington IOUs seek to comply with CETA, they must site and build renewable resources that may be farther away from load centers, which requires more transmission infrastructure… While the transmission-related costs included in the ASCM should be the same for IOUs and preference customers, BPA should include other transmission related costs into the ASCM that better reflects the nature of Washington's statutory environment."

# BPA Staff Proposal – Account 925

- **Discussed at the Dec. 3, 2025 ASCM workshop and introduced in Settlement Concept proposal.**
- **Draft ASCM text:**
  "(w) Injuries and Damages. Costs in FERC Account 925 will be functionalized to Dist/Other.

    (1) State approved Injuries and Damages. Costs from FERC Account 925 approved for retail rate recovery by state commissions will be functionalized using the Labor Ratio. The ASCM will not allow double recovery of these costs housed in other accounts (e.g. Regulatory Assets or Liabilities)." [Part I, Section 301.4(w)]

# Informal Comments – Account 925

- **COUs:** "We recommend that BPA exclude all wildfire related costs from production for purposes of the ASCM on the basis that such costs are (i) likely to arise from the exchanging utility's transmission and distribution business lines and (ii) akin to costs arising from "uncontrollable events" that would be excluded from the §7(b)(2) rate test."
- **IOUs:** "Limiting charges in FERC account 925 to only amounts specifically approved by PUCs is a step backwards... The 2008 ASCM streamlined the ASC process by basing the inputs on FERC Form 1s. This was and remains appropriate because PUC rate proceedings do not always result in a clear determination of injuries and damages that can be reported under FERC account 925."
- **WUTC:** "As part of the post-2028 REP, BPA proposes to include Commission approved costs related to injuries and damages (Account 925) within individual utilities' ASCs. The Commission supports the inclusion of these costs into the ASCM as a baseline as the Commission has seen increased amounts claimed by regulated utilities in Account 925 due to wildfires and extreme weather events… Although the Commission supports the inclusion of these costs into the ASCM, these costs are not always addressed in Commission orders for a variety of reasons and the costs approved by the Commission may differ from what is reported on FERC Form 1."
- **NWPCC:** "The Council is supportive of many of the proposed updates included in the preliminary draft, including the treatment of New Large Single Loads, the updated approach to transmission costs, and the method for incorporating costs for injuries and damages that have been approved by state commissions for rate recovery."

# BPA Staff Proposal – Energy Storage Plant

- **Discussed at the Dec. 3, 2025 ASCM workshop.**
- **Draft ASCM text:**
  "(v) Treatment of Energy Storage Plant: Bonneville will functionalize Energy Storage Plant costs using the PTD ratio." [Part I, Section 301.4(v)]

# Informal Comments – ESP

- **COUs:** "…we are concerned that reliance on this ratio may not always result in a balanced or representative allocation of Energy Storage Device costs, particularly where such resources are developed to address Transmission and/or Distribution needs. In those circumstances, it may be appropriate for BPA to consider alternative ratios that better align cost allocation with the underlying drivers of the investment..."
- **IOUs:** "While the IOUs support consolidation of these accounts consistent with FERC Order 898, the use of the PTD functionalization method may not reflect the specific use of the batteries being installed. The IOUs recommend a direct functionalization method based on reasonable analysis of procurement conditions, interconnection status, or usage characteristics in the base year. This allows utilities to reflect how energy storage devices contribute to a utility's average system cost.
- **WUTC:** "While BPA proposes to functionalize these costs using the PTD plant ratio and include battery storage costs deemed as Production, the Commission's Cost of Service (CoS) rules offer flexibility for IOUs and intervenors to submit their own method of functionalizing these accounts during a rate case. The Commission believes the Commission's rules provide all parties with the flexibility to fully understand how different utilities operate battery storage systems in unique ways..."
- **NWPCC:** "... The process of parsing out the specific attributes of each resource during a rate setting would require significant time and likely be contentious. The Council supports Bonneville's historical approach to functionalizing resource costs using PROD...Energy storage should also receive consistent treatment."

# BPA Staff Proposal – Disallowed Costs

- **Brought up by COUs at the Oct. 23, 2025 ASCM workshop; submitted by COUs as comments on the same workshop.**
- **Draft ASCM text:**

  "Each ASC Filing shall be reviewed by BPA and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the ASC Filing complies with the requirements of this Methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts." [Part II, Section 3.2.1]

# Informal Comments – Disallowed Costs

- **COUs:** "Costs included in FERC accounts that are disallowed by the IOU's regulatory commission(s) for retail ratemaking must be identified (nature and amount) and removed for ASC purposes. This will better align utility ASC filings with retail ratemaking. If the utility's ASC FERC accounting period doesn't match the test period used by the regulatory commission for IOU retail ratemaking, such like disallowed costs should be identified and removed from specific accounts in the utility's ASC filings if applicable."
- **AWEC:** "AWEC supports removal of costs disallowed by a state commission from an IOU's Base Period ASC Filing inputs submitted for ASC purposes. By definition, costs that a state commission has disallowed are unreasonable (in the case of expenses) and imprudent (in the case of capital costs), and therefore do not meet applicable state public interest standards such as "fair, just, reasonable and sufficient rates" and "fair, just and reasonable rates…"

# Comment – Variance Analysis

- **Brought up by COUs at the Oct. 23, 2025 ASCM workshop; submitted by COUs as comments on the same workshop.**
- **Draft ASCM text:**

  "… a separate variance analysis, which includes the accounts (amounts and functionalization) from Appendix 1 Schedules: 1, 3, 3A, 3B, and Load Forecast tab for the current Base Period ASC Filing Appendix 1 and the prior Base Period ASC Filing final Appendix 1 inputs… In years when BPA is not conducting a Base Period ASC Review Process, the Utility shall submit an Informational ASC Filing that includes information outlined in section 2.1.1.1 (a), (b) and (d). [Part II, Sections Section 2.1.1.1(d) and 2.1.2]
- **COUs on variance analysis:** "For each Appendix 1 input, the Base Period ASC filling should establish variance between the current filing year and each of the four previous years as well as between the current filing year and the four-year historical average."

# Comment – Distribution Losses

- **Discussed at the Oct. 23, 2025 ASCM workshop.**
- **Draft ASCM text:**

"(n) Method to Calculate Distribution Losses. The losses will be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss factor will be measured using the following method:

  - Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1.
  - From this 5-year total system loss factor, subtract Bonneville's 12-month weighted average transmission system loss factor.
  - The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP." [Part I, 301.4(n)]

- **IOUs:** "The difference between Method 1 and Method 3 results in a change in the losses applied to eligible retail loads. This change could result in either a positive or negative change in ASC for other utilities... BPA should keep the current options pending additional explanation and discussion between BPA and stakeholders regarding this proposed change."

# Comments – Escalation of ASC

- **Discussed at the Dec. 3, 2025 ASCM workshop.**
- **Draft ASCM text:**
  "(A) The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent five years of actual data (Base Period and prior four years)." [Part I, Section 301.5(b)(2)(ii)(A)]
- **WUTC:** "BPA proposes to utilize a five-year weighted average to escalate the base period ASC to the Rate Period ASC. BPA's rationale for this change is to mitigate the year-over-year volatility of the escalations by smoothing out the weighting ratios over a longer period. After reviewing this proposal, the Commission is supportive of the five-year average..."
- **IOUs:** "The IOUs request that BPA retain the three-year weighted average calculation. The IOUs believe that current prices are a better predictor of future prices. Extending the period considered in calculating the weighted average price reduces the volatility of prices."

# Comment – New Resource Grouping

- **Discussed at the Dec. 3, 2025 workshop.**
- **Draft ASCM text:**
  "(4) Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's ASC within an Exchange Period provided that the major resource addition or reduction results in a 2.5 percent or greater change in a Utility's Base Period ASC. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more." [Part I, Section 301.5(c)(4).
- **IOUs:** "The IOUs believe that resources that come online prior to the Exchange Period should be reflected in the ASC to ensure an accurate representation of system costs. Excluding operational resources due to grouping rules undermines the intent of the methodology and creates distortions in cost recovery… As utilities increasingly integrate smaller, distributed, and emerging technologies, this issue will become more pronounced, making a more flexible and transparent approach essential for fairness and accuracy."

# Comment – NLSLs

- **Discussed at Dec. 3, 2025 workshop.**
- **Draft ASCM text:**

"(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 will be based first on the average costs of 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 legacy NLSLs online prior to the effective date of this 2026 ASCM, the resource costs will be based on the Utility's Base Period ASC.

(3) ASCs will only be adjusted for loads that have been designated as NLSLs prior to the end of the Base Period." [Part I, Section 301.4(p)]

# Comment – NLSLs cont.

- **Draft ASCM text:**
  "(10) Bonneville will escalate the components of the resource costs used to serve NLSLs to the Exchange Period using the following steps:
  - (i) Escalate the components of the fully allocated resource costs to the Exchange Period.
  - (ii) Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.
  - (iii) The cost to serve NLSLs may change when the ASC changes due to resource additions/retirements.
  - (iv) The Exchange Period NLSL load will equal the Base Period NLSL load." [Part I, Section 301.5(c)(10)]
- **IOUs on NLSLs:** "The IOUs request that BPA delay implementing the above proposed changes pending further discussion."

# Comment – ASC Review Process

- **Brought up by COUs in comments on the Oct. 23, 2025 ASCM workshop.**
- **Draft ASCM text:**
  "The ASC Review Process commences on June 1 of the Review Period, or such other date as may be established by BPA (Day 1). BPA will review all Utilities' ASCs concurrently in a public process... Each spring prior to a Review Period, BPA will post on its ASCM website (https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings or its successor), a detailed schedule, accommodating applicable holidays and weekends, that shall be the official schedule for that Review Period." [Part II, Sections 4.1 and 4.2]
- **COUs:** "To enhance transparency and ensure stakeholder engagement, BPA should incorporate into its ASC review procedures a requirement that each review process begin with a publicly noticed workshop (such as via tech forum) held at least two weeks before the review process formally begins."

# Comment – ASC Consultation

- **Brought up by COUs in Nov. 24 comments, discussed at Dec. 16, 2025 workshop**
- **Draft ASCM text:**

  "(a) The Administrator, at his or her discretion, 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.

  (b) The Administrator will not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, that is, one year after the then existing ASC Methodology is adopted by Bonneville and approved by the Commission, through interim or final approval, whichever occurs first.

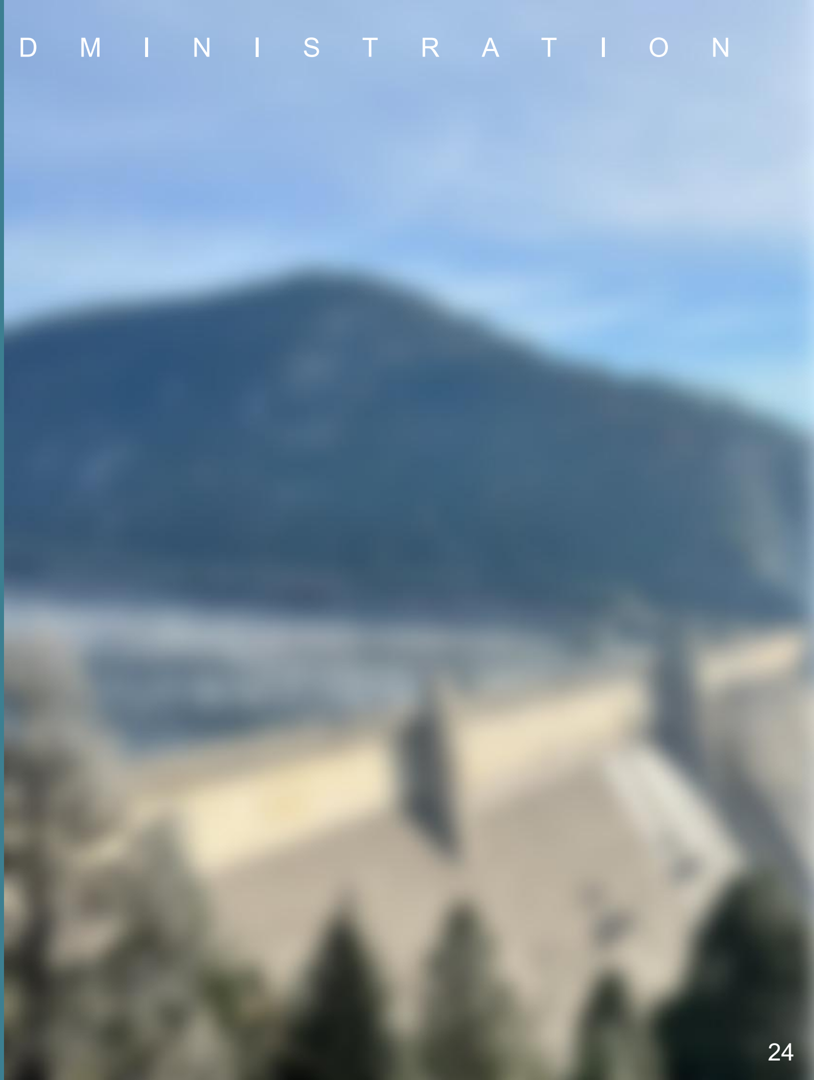
  (c) The Administrator may, from time to time, issue interpretations of the ASC methodology. The Administrator also may modify the functionalization code of any Account to comply with the limitations identified in Sections 5(c)(7)(A)-(C) of the Northwest Power Act or to conform to Commission revisions to the Uniform System of Accounts." [Part I, Section 301.6]
- **COUs on ASC Consultation Process:** "The COUs oppose BPA's proposed rewrite section 301.6. to exclude customer groups – COUs and IOUs – from initiating a 5(c)(7) consultation process. The COUs strongly recommend that BPA maintain the language from the 2008 ASCM."

# Q&A

# Closeout

## Presenter – Scott Winner

Power Planning and Forecasting Supervisor



POST 2028 REP

# Phase 2 Schedule Update

| Date | RPSA | ASCM |
| --- | --- | --- |
| Jan 21, Wed | **Comments due**, Full draft | **Comments due**, Preliminary draft |
| Jan 27, Tues | | **Workshop**, Preliminary comments |
| Feb 3, Tue | | **Post**, Incremental draft |
| Feb 10, Tues | | **Comments due**, Incremental |
| Feb 13, Fri | | **Workshop**, Incremental comments |
| Feb 20, Fri | | **Post**, Full draft |
| Mar 6, Fri (est.) | **ROD publication** | |
| Apr 2, Thurs | | **Comments due**, Full |
| May 22, Fri (est.) | | **ROD publication** |

# Communication and Resources

- Submit written comments and questions to rep2028@bpa.gov.

- Details to attend all Post-2028 REP Phase 2 workshop can be found on BPA's event calendar.

- For REP background, post-2028 public workshop materials, public notices, and additional REP resources, go to the Post-2028 REP webpage.

- To receive pertinent notifications related to this process sign up for Tech Forum.

# Thank you!

## Post 2028 REP Team