<u>IOU Informal Comments in Response to BPA Preliminary Draft Average System Cost Methodology ("ASCM")</u>

Submitted to REP2028@bpa.gov

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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 preliminary informal comments in response to Bonneville Power Administration's ("BPA") Preliminary Draft Average System Cost Methodology ("Preliminary Draft ASCM").[1]

I. Introduction and Background

On December 10, 2025, BPA posted the Preliminary Draft ASCM for review and comment. The Preliminary Draft ASCM includes changes as identified and discussed in workshops held on October 23, December 3, and December 16, 2025.[2] In the Preliminary Draft ASCM BPA proposes structural changes to the existing 2008 ASCM. In general, these structural changes include:

- Changes to the structure to create two parts. Part 1 consists of FERC regulations and Part 2 consists of BPA's rules of procedures for determining Average System Cost ("ASC").
- Changes to the structure of the ASCM by moving substantive text from the endnotes into the body of the ASCM.
- Removal of references to Consumer Owned Utilities ("COUs") and related concepts not applicable to IOUs.
- Changes to the treatment of specific accounts including reduction of allowable expenses or changes to the functionalization method.

The IOUs support the need for BPA to periodically update the ASCM and appreciate BPA's efforts to do so here. However, the IOUs disagree with several of BPA's proposed changes and offer informal comments on the following.[3] The IOUs request that BPA address these comments

[1] Preliminary Draft Average System Cost Methodology (December 10, 2025), available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/2026-ascm-preliminary-draft-clean.doc, included as Attachment 1.

[2] The presentation given by BPA at the October 23, 2025 workshop can be found on the BPA website here https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/phase-2-post-2028-rep-ascm-workshop-20251023.pdf, included as Attachment 2; the presentation given by BPA at the December 3, 2025 workshop can be found on the BPA website here https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20251203-phase-2-post-2028-rep-ascm-workshop.pdf, included as Attachment 3; the presentation given by BPA at the December 16, 2025 workshop can be found on the BPA website here https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20251216-phase-2-post-2028-rep-ascm-workshop-3.pdf, included as Attachment 4.

[3] The IOUs are still evaluating the Preliminary Draft ASCM, and for several of BPA's proposed changes, as discussed below, the IOUs need additional information from BPA before they can comment fully. By not providing comments on any issue not identified below or addressed in these informal comments, the IOUs in no way waive the right to comment and reserve the right to address any such issue in the future.

directly in its next draft ASCM, and, in particular, address the below-noted substantive concerns, which are discussed in more detail in section II below.

1. Method to Calculate Distribution Losses
2. Change to New Large Single Loads ("NLSL")
3. Treatment of FERC Order 888
4. Treatment of Energy Storage Plant
5. Limitation on Injuries and Damages
6. Limitation Transmission Costs
7. Change to Determination of Average Short Term Purchased Power Prices and Sales for Resale Prices
8. Definitions

In addition to comments on BPA's proposed changes, the IOUs also identified two issues within the existing ASCM methodology that are not addressed in the Preliminary Draft ASCM, but have the potential to materially affect the calculation of ASC and Residential Exchange Program benefits. These issues have been present in prior iterations of the ASCM and are reflected in the current Forecast Model and ASC implementation practices. Specifically, the IOUs request that BPA consider reviewing and updating:

1. The methodology used to forecast electric market prices for power purchases required to serve load growth not met by major resource additions; and
2. The materiality threshold applied to the inclusion of new resources in a utility's ASC.

Although the above two items are not proposed changes in the Preliminary Draft ASCM, the IOUs believe they warrant discussion and modification as part of BPA's broader ASCM update to ensure that ASCs reasonably reflect utility costs and avoid outcomes that are inconsistent with operational and market realities.

The remainder of these informal comments focus on the substantive issues outlined above.

II. The IOUs' Informal Comment to Select Proposals in the Preliminary Draft ASCM

1. <u>Method to Calculate Distribution Losses</u>[4]

BPA proposes – without any explanation – 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. The IOUs do not support this change. Most of the IOUs currently use Method 1, although some use Method 3. 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

[4] BPA proposed at the October 23, 2025 workshop to move certain endnotes from the 2008 ASCM to the body of the ASCM, and reflected this change in redline in the Average System Costs Methodology Redlined – Part One document. *See* Attachment 2 at Slide 45 and Average System Costs Methodology Redlined – Part One document at page 65, available at https://www.bpa.gov/-/media/Aep/power/residential-exchange-program/post-2028-rep/20251023-tf-pt-1-redlined-rpsa-ascm.doc. BPA updated Preliminary Draft ASCM § 301.4(n) to include only Method 3.

ASC for other utilities. BPA has not provided sufficient support for this change, other than to reduce available options. BPA should keep the current options pending additional explanation and discussion between BPA and stakeholders regarding this proposed change.

2. Change to New Large Single Loads ("NLSL")[5]

In the Preliminary Draft ASCM, the IOUs understand that BPA proposes 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 costs to serve NLSL, removing the NLSL Exception, and removing the NLSL Formula rate.

The IOUs request that BPA delay implementing the above proposed changes pending further discussion. In particular, the IOUs are still evaluating BPA's escalation and NLSL Exception proposals. The IOUs do not believe BPA has adequately justified these proposed changes and request that BPA provide additional information and explanation regarding its proposals.

Regarding BPA's proposed Formula Rate change, the IOUs disagree with this change. BPA has failed to adequately explain its reasoning for this change, and mid-period adjustments should remain available to support the timely recognition of NLSLs that become operational during an Exchange Period.

3. Treatment of FERC Order 888

The 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. As discussed below, the IOUs disagree with BPA's transmission cost proposal; therefore, BPA's proposal above is unnecessary.

4. Treatment of Energy Storage Plant[6]

BPA proposes to update the Energy Storage Plant accounts to comply with FERC Order 898. Previously, three accounts (FERC accounts 348, 353, and 361) were reported separately and had specific functionalization. Consistent with Order 898, BPA proposes moving these into one account and using the Production/Transmission/Distribution ("PTD") labor ratio functionalization method.

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.

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[5] Preliminary Draft ASCM §§ 301.4(p), 301.5(c)(10).
[6] Preliminary Draft ASCM § 301.4(v).

5. Limitation on Injuries and Damages[7]

BPA proposes limiting the charges in FERC account 925, Injuries and Damages, to only amounts approved for recovery by state public utility commissions ("PUCs"). The IOUs do not support this change and further discussion is needed regarding alternatives.

Limiting charges in FERC account 925 to only amounts specifically approved by PUCs is a step backwards. The current FERC Form 1 process adopted in the 2008 ASCM was specifically implemented to avoid the labor-intensive ASC methodologies of the past the relied heavily on PUC rate proceedings. 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. For example, PUCs sometimes disallow costs for reasons not tied to the validity of the cost to generate and provide power to customers, or PUC proceedings are settled without a clear determination of injuries and damages. The FERC Form 1 approach was adopted, in part, to avoid these the inefficiencies and have been a straightforward and consistent approach to reporting FERC account 925 amounts. BPA's proposed treatment also unfairly impacts IOUs because IOUs are subject to costs associated with wildfires and other litigation that COUs and BPA are not subject to.

While the IOUs acknowledge BPA's concern over the increase in wildfire and other litigation costs, the IOUs believe further discussion is warranted to discuss alternatives to BPA's proposal.

6. Limitation on Transmission Costs[8]

BPA proposes to exclude all functionalized transmission costs other than those in FERC account 565, third-party wheeling transmission costs and account 447, transmission associated for sales for resale. The IOUs do not support this change, which is inconsistent with Section 5(c)(7) of the Northwest Power Act ("NWPA"), and with how the ASC has been calculated for decades.

Under the NWPA, a utility's ASC "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" and "subject to review and approval by the Federal Energy Regulatory Commission." NWPA § 5(c)(7). The only statutory exclusions on what the ASC "shall not include" do not mention transmission. The exclusions are the costs to serve any new large single load of the utility (Section 5(c)(7)(A)), the cost of additional resources in an amount sufficient to meet any additional load outside the region (Section 5(c)(7)(B)), and any costs of any generating facility which is terminated prior to initial commercial operation (Section 5(c)(7)(C)).

Accordingly, since the inception of the NWPA, transmission costs have always been included as part of the utility's ASC. Most recently, in the 2008 ASCM, *BPA staff* expressly advocated for the inclusion of transmission costs in a utility's ASC:

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[7] Preliminary Draft ASCM § 301.4(w).
[8] Preliminary Draft ASCM § 301.4(x).

> Transmission costs are a cost to a Utility of delivering power to load and should be included in the calculation of a Utility's ASC. Increasingly, utilities rely on transmission to find the least cost resource available to serve load. This includes bringing power to load from distant, lower cost generation, particularly renewable resources such as wind where moving fuel to local generation is not an option. In addition, dramatic changes in the electricity industry have taken place since BPA originally developed the 1984 ASCM, such as increased reliance on independent power producers to develop generation to sell at market ("merchant plant") or under long-term power purchase agreements; strengthening of wholesale power markets; increased reliance on planning and operating the region's transmission system under a "one Utility" vision through ColumbiaGrid (an independent regional transmission entity); the creation of an Independent System Operator in California; and a more constrained transmission system. These changes support including transmission as a cost of ASC. BPA should, therefore, include transmission as a component of ASC.[9]

The 2008 ASCM Record of Decision contains a detailed and well-reasoned decision approving the inclusion of all transmission costs in calculating a utility's ASC.[10] The conditions that existed in 2008 that BPA determined justified the inclusion of all transmission costs in calculating ASC are still in effect today. BPA has failed to explain how its proposed changes are warranted, particularly given the circumstances and reasoning in the 2008 ASCM Record of Decision.

Accordingly, the IOUs strongly oppose BPA's transmission cost proposal. Excluding transmission costs harms IOU customers. If IOUs and their customers had access to BPA federal power, then IOU transmission costs would be lower, as the IOUs would not need to procure resources farther away. 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. Therefore, the IOUs believe that the cost of transmission should remain in the ASCM.

7. Change to Determination of Average Short Term Purchased Power Prices and Sales for Resale Prices[11]

The Preliminary Draft ASCM proposes to change the determination of average short term purchased power prices and sales for resale prices from three years to five years.

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. In periods of increasing

[9] 2008 ASCM Record of Decision at 126.
[10] *Id.* at 125–42.
[11] Preliminary Draft ASCM § 301.5(b)(2)(ii)(A).

or decreasing prices a longer period reduces or increases the calculated price. The calculated price in either case will still be different than the most current period's price. To the extent that this price factors into the calculated or forecasted ASC then the result is potentially less accurate, impacting the calculated Residential Exchange Program benefit pool.

8. Definitions[12]

The IOUs oppose the proposed deletion of the definition of "Priority Firm Power". 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 observes 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 Residential Exchange Program as a physical exchange.[13]

III. IOU Proposed Changes to the Existing ASC Methodology

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

Under the existing ASCM Forecast Model, BPA forecasts the electric market price used to serve load growth not met by major resource additions by calculating average short-term purchased power prices and average sales for resale prices over recent historical periods. These values are used to calculate a market price applied to incremental load during the Exchange Period.

As implemented, this methodology can produce purchased power prices that are materially below reasonable expectations of the prices utilities can obtain in the market. In some cases, the forecasted prices are significantly lower than a utility's average cost of serving load and do not reflect observable market conditions or procurement experience.

The IOUs are concerned that the existing methodology systematically understates the cost of serving load growth not met by new resources. The assumption that incremental load can be served at extremely low market prices does not reflect how utilities actually procure power and results in ASCs that are not representative of underlying costs. For example, assuming incremental load can be served at market prices ignores the increasingly stringent environmental requirements imposed on utilities that typically cannot be met through market purchases.[14]

When applied across the Exchange Period, these low market price forecasts effectively price all unmet load growth at levels that are inconsistent with market realities and environmental

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[12] Preliminary Draft ASCM § 301.2.
[13] *See* IOU Comments in Response to BPA Draft Post-2028 Residential Purchase and Sale Agreement, being submitted concurrently with these comments.
[14] *Id*.

requirements. This outcome understates purchased power costs and materially affects the calculation of the ASC and Residential Exchange Program benefits.

The IOUs recognize the inherent uncertainty in forecasting future market prices. However, the existing approach produces outcomes that are not reasonable and do not align with utility experience. The IOUs recommend that BPA revise the existing methodology and, at a minimum, establish a reasonable floor on forecasted purchased power prices to ensure that the cost of serving unmet load growth is not understated.

2. <u>Materiality Threshold for Inclusion of New Resources in the ASC</u>

Under the existing ASCM, new resources that are not reflected in the FERC Form 1 used for a utility's ASC filing are subject to a materiality threshold. Each individual resource must result in a change of at least 0.5 percent of the utility's Base Period ASC to be eligible for inclusion in a group, and the grouped resources must collectively result in a change of at least 2.5 percent of the Base Period ASC to be included. The Exchange Period ASC is intended to reflect a utility's system costs, including resources that come online after the Base Period but prior to the Exchange Period.

The IOUs are concerned that the existing materiality threshold and grouping requirements can 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.

While grouping is permitted, the current approach creates unintended outcomes. If multiple resources are grouped to meet the 2.5 percent threshold and a single resource in the group does not come online prior to the Exchange Period, none of the remaining resources in the group are included in the ASC, even if they are operational and represent a substantial portion of total costs.

For example, if a utility brings five small battery resources online, each exceeding the 0.5 percent individual threshold and collectively exceeding the 2.5 percent threshold, and one resource is delayed, the remaining resources—even if fully operational—would be excluded from the ASC. This outcome understates actual system costs and is inconsistent with the purpose of the Exchange Period ASC.

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. The IOUs urge BPA to explore methodologies that would allow for inclusion of all used and useful resources without increasing administrative burden to BPA. 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.

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

Attachment 1
Preliminary Draft Average System Cost Methodology
December 10, 2025

Preliminary Draft of BPA's 2026 Average System Cost Methodology

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) 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 the following method:

(1) 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.

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

(3) 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: Bonneville will functionalize Energy Storage Plant costs using the PTD ratio.

(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).

(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 five years of actual data (Base Period and prior 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 four years) will be calculated. The following weighting scale will be used:

(1) Five (5) times Base Period spread.

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

(3) Three (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 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.

(5) At the time the Utility submits its Appendix 1 filing, the Utility will provide its forecast of ma-

jor 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 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 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 2026 Average System Cost Methodology 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	
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:					

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Distribution Plant	360-374	DIST		CD	
Energy Storage Plant:					
Energy Storage Plant	387-387.12	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	
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	108	PROD		CONSTANT	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Plant					
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 Plant - Account 303	111	DIRECT	DIST	CONSTANT	
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	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Nuclear Fuel	120.1-120.6	PROD		NFUEL	
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT	
Common Plant	356	DIRECT		CONSTANT	
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 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Stores Expense Undis-tributed	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 Ex-penses	181	PTDG		CONSTANT	
Extraordinary Property Losses	182.1	DIRECT	DIST	CONSTANT	
Unrecovered Plant and Regulatory Study Costs	182.2	DIRECT	DIST	CONSTANT	
Other Regulatory Assets	182.3	DIRECT	DIST	CONSTANT	
Preliminary Survey and Investigation Charges (Major only)	183	DIST		CONSTANT	
Clearing Accounts	184	DIST		CONSTANT	
Temporary Facilities	185	PTDG		CONSTANT	
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT	
Deferred Losses from	187	DIRECT	DIST	CONSTANT	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Disposition of Utility Plant					
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	
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 Re-	257	PTDG		CONSTANT	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
acquired Debt					
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	
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	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
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	
Other Expenses	557	PROD		CONSTANT	
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:					

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Total Customer Accounts	901-905	DIST		CACNT	
Supervision	907	DIST		CSERV	
Customer assistance expenses (Major only)	908	DIST		CSERV	d/
Customer Service and Information	909-910	DIST		CSALES	
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 Ex-	930.1	DIST		A&G	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
penses					
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	
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	404	DIRECT		CONSTANT	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Term Electric Plant					
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	
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	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
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/
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	

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Account Description	**Acct No.**	**Functionalization**		**Escalation Codes**	**Endnote**
		Default	**Optional**		
Customer Service and Informational		DIST		WAGES	
Sales		DIST		WAGES	
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
k/ See section 301.4.v

18 CFR PT. 301, APP. 1

Appendix 1 to Part 301--ASC Utility Filing Template

DEPARTMENT OF ENERGY

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 Principles, and is consistent with applicable orders and policies of the Utility's Regulatory Body;

(f) 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 BPA 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 determination, 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 the granting 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 within three 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 review all Utilities' ASCs concurrently in a public 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. 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.

4.4.2. 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:

4.4.2.1. Identify the contested information; and
4.4.2.2. Assert and explain why the information does not fall within the definition of Confidential Information.

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.

4.4.4. 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. 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.

5.4. ction.

5.5. tion.

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

5.7. 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

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 ASCM Presentation
October 23, 2025

Post-2028 Residential Exchange Program Average System Cost Methodology Workshop 1

October 23, 2025

9:00 am – 4:00 pm

RHR and WebEx

POST 2028 REP

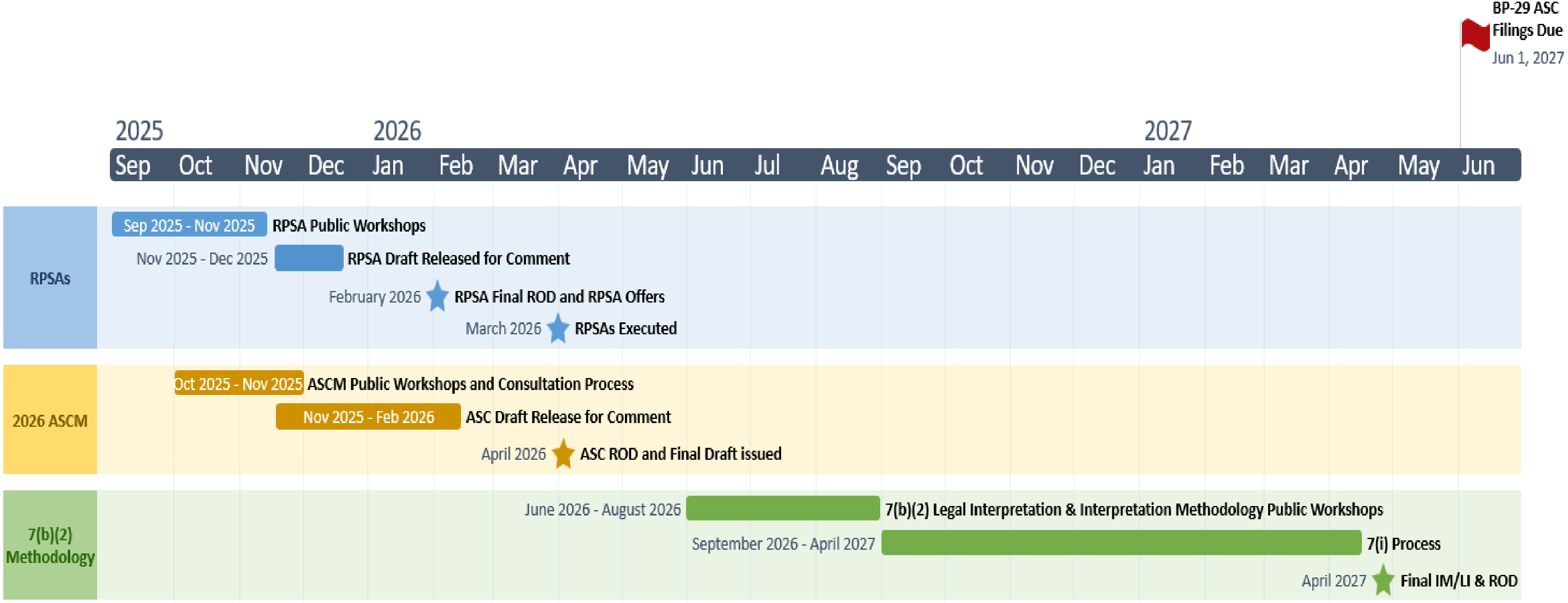
October 23rd Workshop Agenda

Workshop #1 Topics	Presenter(s)
Opening Remarks	Kim Thompson
Introductions and Agenda	Scott Winner
Phase 2 Engagement and ASCM Process	Paulina Cornejo
ASCM Background	Rich Greene
Calculating ASCs under 2008 ASCM	Michael Edwards
PART I: ASCM and Appendix 1	Rich Greene/Michael Edwards
PART I: ASCM Structure	Paulina Cornejo
PART I: ASCM Proposed to Carry Forward and Proposed Updates	Michael Edwards
PART I: FERC Accounts	Scott Winner
PART I: Functional Overview Appendix 1	Michael Edwards
PART II: Rules of Procedure	Michael Edwards
Workshop 2 Topics and Closeout	Scott Winner
Breaks	**Est. Times**
LUNCH	Noon – 1:00 pm

Post-2028 REP Team

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

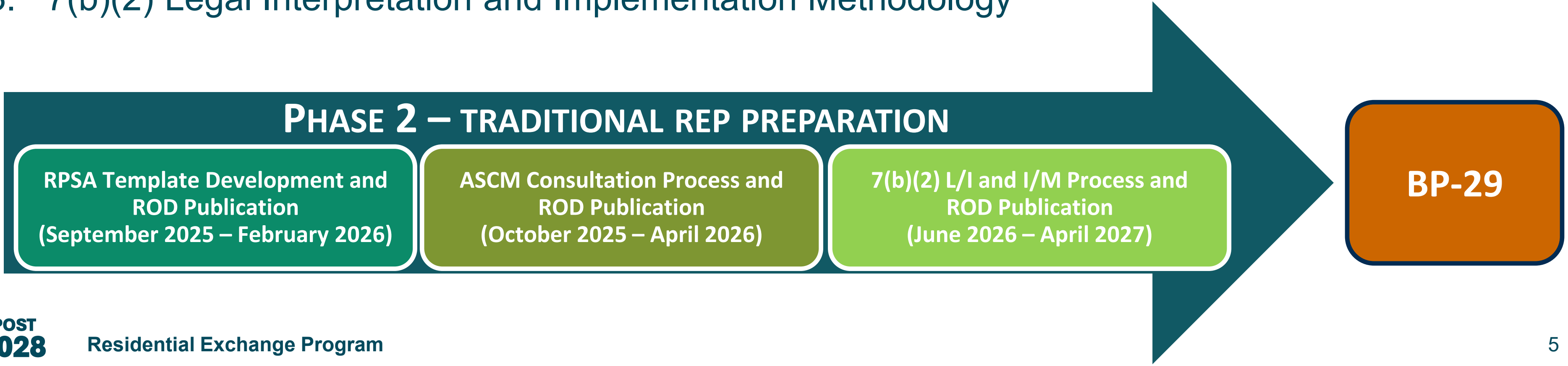
Phase 2 Public Engagement Timeline



Phase 2 Public Engagement Process

Phase 2 focuses the post-2028 REP Public Engagement Process on development of three foundational components to prepare for a traditional implementation of the REP post-expiration of the 2012 REP Settlement agreements. The 2012 Settlement expires September 30, 2028.

1. Residential Purchase and Sale Agreements (RPSA)
2. Average System Cost Methodology (ASCM)
3. 7(b)(2) Legal Interpretation and Implementation Methodology



Phase 2 Public Engagement Objectives

Bonneville's objectives for Phase 2 of the Post-2028 REP efforts are to:

- Complete Phase 2 before BPA's BP-29 Rate Case Proceedings. **Phase 2 target completion date is April 2027.**
- Facilitate a robust engagement process for BPA and regional parties to constructively work through applicable issues.

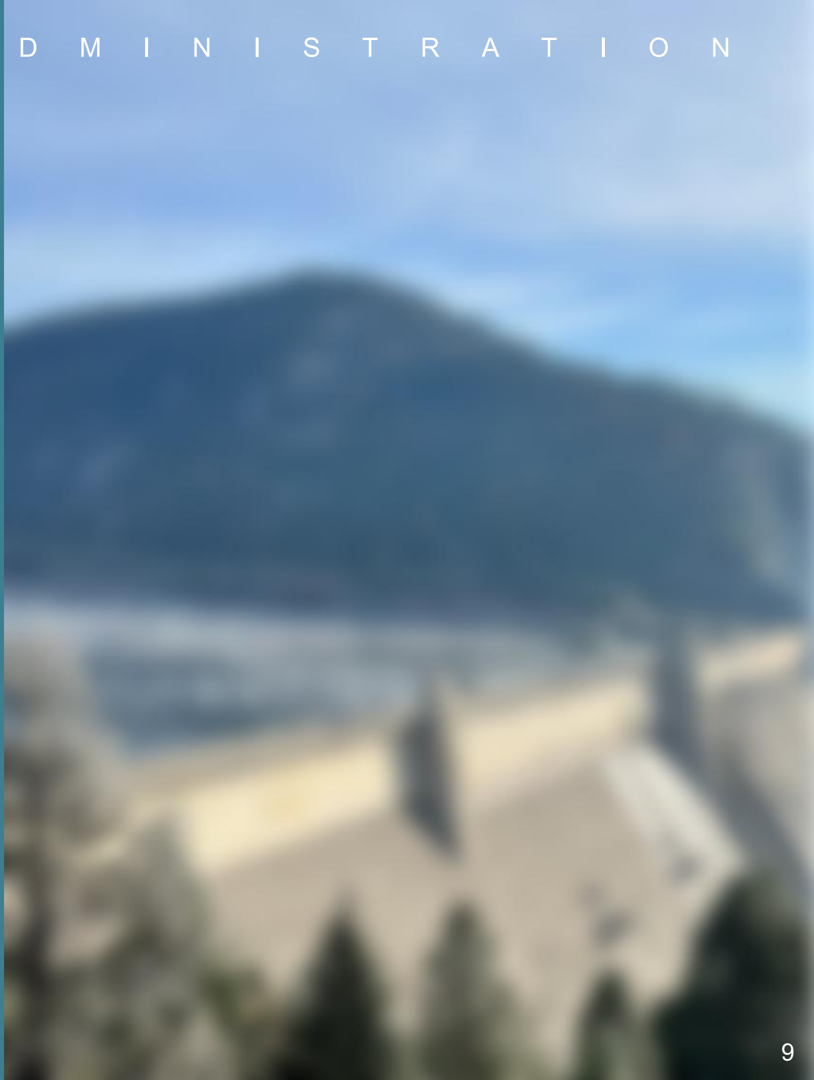
Phase 2 Public Engagement Approach

Broad approach to successfully achieve Phase 2 objectives:

- ❖ Hold regular public in-person workshops that include a virtual participation option. *BPA encourages parties that intend to engage in significant discussions to attend in-person.*
- ❖ Foster a collaborative workshop environment through informative presentations.
- ❖ Communicate priorities and expectations in each of the three Phase 2 processes.
- ❖ Provide multiple opportunities for regional parties to submit comments, feedback and questions.
- ❖ Respect one another and assume good intentions. Bring a constructive mentality. Be solution-oriented. Identify “parking lot” items for complicated / technical issues.

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.



ASCM Process

Presenter – Paulina Cornejo

REP Policy Lead

ASCM Engagement Timeline

ASCM Engagement Timeline - Matrix

Event	ASCM Workshops				ASCM Drafts and ROD
	WS1	WS2	WS3	WS4	
ASCM WS 1	10/23				
ASCM WS 2		11/5			
ASCM WS 3			11/20		
ASCM Preliminary Draft Released					11/25
ASCM WS 4				12/3	
Informal Feedback due on Preliminary Draft					12/15
ASCM Full Draft Released					January 12th, 2026
Comments due on Full Draft					February 13th, 2026
ASCM Final draft and ROD					April 13th, 2026

Structure of ASCM Workshops

Workshop Structure

- BPA will host a total of four one-day workshops between October and November. Workshops are scheduled to begin at 9AM and will vary in length dependent on content. See BPA's Event Calendar for specific timeframes.
- ASCM workshops will commence with Workshop 1 on October 23rd, 2025.
- BPA will post workshop materials to the Post-2028 REP external site three business days in advance whenever possible.
- The fourth ASCM workshop BPA is scheduled to occur following the publication of the preliminary ASCM draft on Tuesday, December 3rd and will address that document.

Additional Content in Workshops Two Through Four:

- Participant questions and BPA responses on previous workshop content.
- Participant-led topics on previous workshop content and discussion.
- Additional time allotted for topics from the previous workshops as necessary.

ASCM Workshop Topics

Workshop 1: Oct. 23rd	Workshop 2: Nov. 5th	Workshop 3: Nov. 20th	Workshop 4: Dec. 3rd
• ASCM Structure • ASC Review Process and Rules of Procedures • Sections Carried Forward • Updates to FERC Accounts and ASCM Sections • Functional Overview of Appendix 1 and Forecast Model • WS 2 Topics	Topics: • Transmission Costs • Injuries and Damages (Account 925) • Energy Storage Devices More ASCM Proposals: • Calculation of NLSL Costs • Source of Escalation Data • Meeting Load Growth	• Wrap-up pending topics from WS 1 and 2 • Revisions to the Appendix 1 Template and Forecast Model • Customer-led Topics	• Discussion is focused on Preliminary ASCM Draft

ASCM Engagement Methods

	Informal 1: Participants may submit informal feedback on workshop topics and discussion after each workshop.	**Informal 2: Participants may submit informal feedback on the full preliminary draft ASCM after its release on November 25th.**	**Formal Comment: BPA will open a public formal comment period on January 12th, 2025, to respond to the Draft ASCM.**
Comment Deadline	Feedback submittal is due within 1 week following each workshop.	Comments will be due by **COB Tuesday, December 15th.**	Formal comments will be due by **COB Friday, February 13th.**
Comment Repository	via email to **REP2028@bpa.gov**	via email to **REP2028@bpa.gov**	Upload to a "Comments" page created for the Post-2028 REP process on bpa.gov. *Details to upload comments will be provided at Workshop 4.*
BPA Responses	BPA will consider all comments received and attempt to respond as applicable and as time permits at a subsequent workshop.	A redline copy will accompany the preliminary draft to crosswalk to initial provision.	BPA will provide its responses to formal comments in a published Record of Decision, accompanied by the final ASCM.

Preliminary and Draft ASCM

Full Preliminary Draft ASCM :

- An initial, preliminary, draft of the full ASCM will be released on November 25th for informal feedback.
- BPA will hold a workshop on December 3rd to discuss the full preliminary draft.
- An informal feedback period will open for three weeks. Feedback on the full preliminary draft will be due **December 15th**.

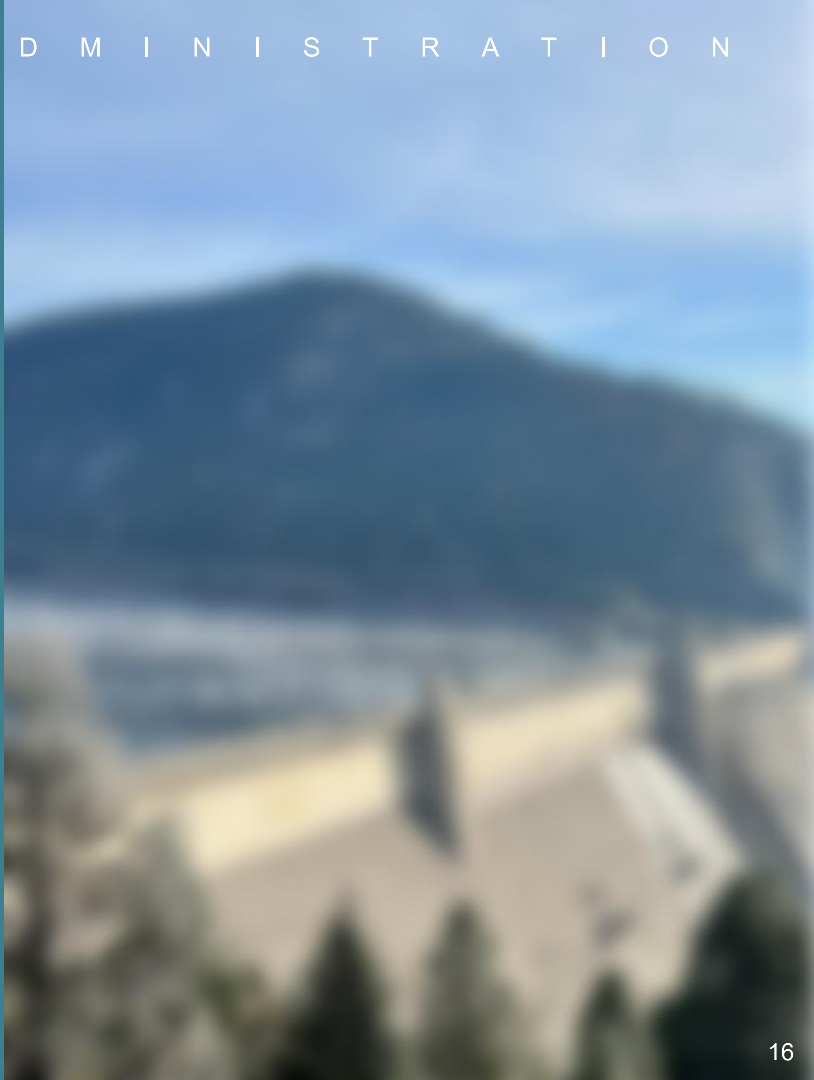
Full Draft ASCM:

- The Full Draft ASCM will be released on January 12th, 2026, for formal comment.
- Participant's formal comments will be due by COB **February 13th, 2026**.
- These comments will be considered in the ASCM ROD.
- ***Target date for release of the ASCM ROD and Final ASCM is April 13th, 2026.***

ASCM Background

Presenter – Richard Greene

Senior Attorney-Advisor



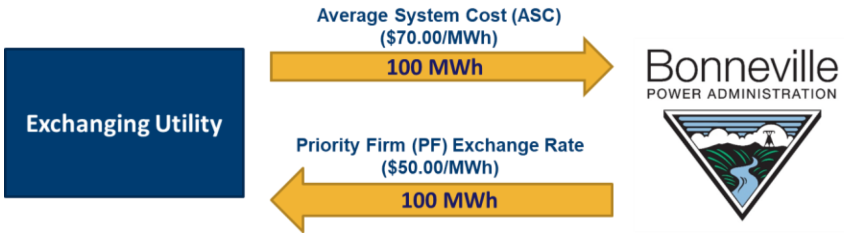
POST 2028 REP

Preceding the 1980 NWPA

- Load forecasts in the 1970s predicted energy requirements would triple over the next two decades.
- BPA had sold to IOUs until 1973; thereafter, BPA stopped selling to IOUs because of preference.
  - Preference provisions of federal law require BPA to sell power to public customers first. BPA forecasted supply of federal power would run out by 1983 to meet public loads.
- Federal, private and public utilities collaborated to build new generation and transmission to meet future needs. The Hydro-Thermal Power Program proposed building 20 nuclear power plans, and 2 coal.
  - HTPP faced a slew of issues, including costs overruns, construction delays, community and environmental opposition, and reduced power forecasts.
  - Such costs in retail rates sharply increased costs to serve regional customers of IOUs and COUs.
- IOUs consumers were hit 3xs harder than those of public utilities.
- As rates between private and public utilities diverge, political pressure built to provide consumers of IOUs with a share of low-cost federal power.
- State of Oregon passed legislation to create state-wide preference customer (covering residential and farm customers). Other states threatened to pass similar legislation.
- Legal battles loomed over allocation of federal power among preference customers and states.

What is an ASC?

- **Section 5(c)(1) of the NWPA**
  - Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the **average system cost (ASC)** of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.
- **An ASC is:**
  - The sum of a utility's resources costs,
  - expressed as a $/MWh rate, and
  - used to calculate an exchanging utility's financial REP benefits.



Section 5(c) of the NWPA

Section 5(c) of NWPA
(ASC Methodology)

Sections 3(18),
5(c)(1) of NWPA

(Average System Cost – PF Exchange Rate) x Res&Farm Load = REP $$$

Section 7(b)(2) of NWPA
(Legal Interpretation)
(7(b)(2) Methodology)

Section 5(c) and the ASC Methodology

- **Section 5(c)(7) of the NWPA directs BPA to determine a methodology to calculate exchanging utilities' ASCs. The ASCM is that methodology.**
  - In consultation with the Council, BPA's customers, and State regulatory bodies.
  - Subject to FERC review and approval.
- **BPA has had three ASC methodologies**.
  - 1981 and 1984 ASC Methodologies required 50+ staff to implement.
  - 2008 ASC Methodology streamlined the ASC process.
- **NWPA only stipulates the methodology must exclude the following costs:**
  - the cost of additional resources in an amount sufficient to serve any new large single load (NLSL) of the utility,
  - the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980, and
  - any costs of any generating facility which is terminated prior to initial commercial operation.

Previous ASCMs

- The 1981 ASC Methodology
  - Following passage of the NWPA, BPA and regional parties collaborated to establish the first ASCM.
  - ASCs based costs on utilities' state commission filings (jurisdictional costing approach) creating a complex review process.
  - Consensus-based methodology. DSIs would pay for first 5 years, so their support was important. DSIs dropped most objections (initially).
  - Allowed "transmission-only" exchange – Public customers could participate with transmission alone.
- The 1984 ASC Methodology
  - Substantial changes in allowable costs – most significantly, limiting transmission expenses, excluding Federal and state income taxes and placing ROI restrictions.
  - Established a 210-day ASC review and determination process yet retained ASCs base costs from rate filings.
  - Exclusion of ROI and Fed. Income tax challenged at Ninth Circuit. Affirmed in *PacifiCorp v. FERC*, (9th Cir. 1986). (Court did not support a "permanent" exclusion of these costs).
  - Court relied on *Alcoa* and *Chevron* to defer to BPA's interpretation.
- Both ASCMs were labor intensive, requiring up to 50 BPA and contract analysts, legal staff and supervisors to conduct reviews.

Context Preceding 2008 ASCM

- 2000 REP Settlement Agreements
  - In 2000, BPA and the parties settled the REP through 2011 (FY 2002-2011)
    - During this period, no ASCs were filed or reviewed by BPA
- Parties go to Court – *PGE vs BPA*
  - Held that BPA was not in compliance with sections 5(c) and 7(b)
  - In May 2007, the Ninth Circuit invalidated the 2000 REP Settlement agreements
  - Court remanded WP-02 rates because of REP Settlement costs
- BPA's Response - Revise Rates and Calculate Refunds
  - BPA issued new Record of Decision (ROD) to respond to Court
  - Revised WP-07 rates – calculated ASCs and implemented 7(b)(2) rate test
  - Calculated refunds – determined that BPA overpaid IOUs ~$1.2B in REP payments
- Re-created BPA function to implement the REP
  - Residential Exchange Program work group was reformed
  - 2008 ASCM replaced the 1984 ASCM

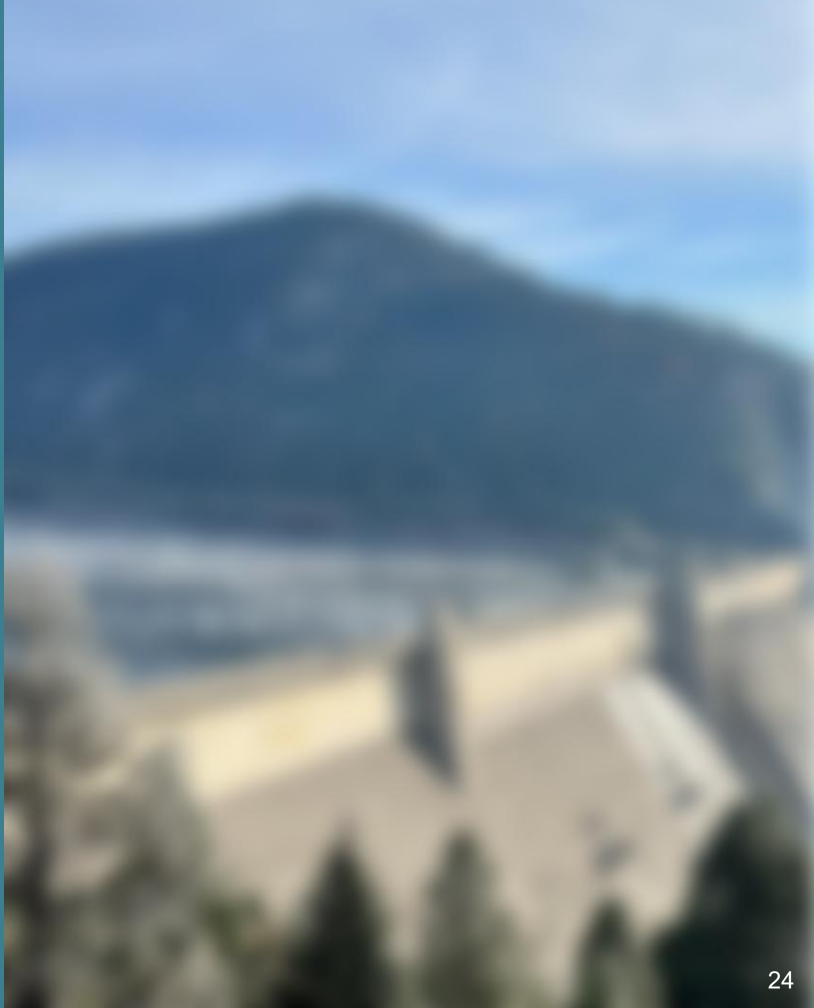
2008 ASC Methodology

- Substantial revisions to form/structure of ASCM.
- ASCM ROD included over 60 substantive sub-issues.
- Streamlined the review process
  - ASCs based on FERC Form 1s (IOUs) and comparable audited financial statements (COUs).
  - Singular ASC review and determination process running parallel to BPA's rate case proceedings.
  - Limited within-rate period changes to ASC (materiality threshold).
- Primary changes:
  - New treatment of transmission costs, return on equity and taxes:
    - Include all costs related to transmission investments and expenses
    - Allow utilities to exchange ROE
    - Permit the exchange of certain taxes
  - COUs with CHWM contracts agreed to not exchange costs to serve Above-RHWM load
- FERC reviewed; deferred to BPA
  - No challenges in Ninth Circuit.

Calculating ASCs under 2008 ASCM

Presenter – Michael Edwards

REP Technical Lead



Calculating REP-Utilities' ASCs ($/MWh)

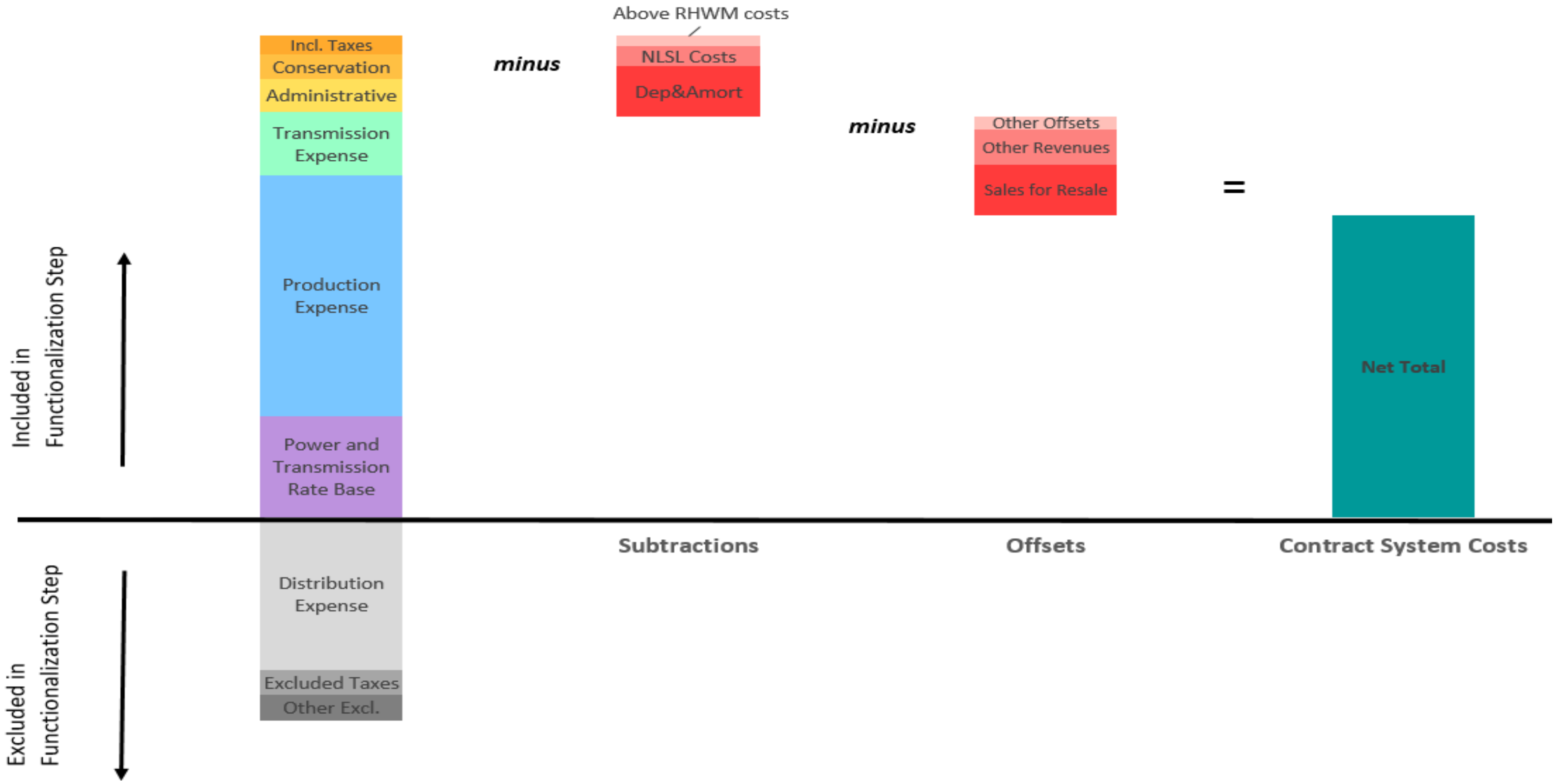
- **The 2008 ASCM ASC is comprised of Contract System Costs and Contract System Load, expressed in $/MWh**

- **Contract System Costs (CSC):**
  - ROR Portion of P&T Rate Base
  - Production and Transmission Expense
  - Administrative and General Expenses
  - Conservation Expenses
  - Labor and State Property Taxes
  - Offsets:
    - Sales for Resales
    - Other Revenues and Other Offsets
    - Costs to serve NLSLs

- **Contract System Load (CSL):**
  - Total "regional" retail load
  - Distribution Losses
  - LESS:
    - NLSLs

$$ASC = \frac{\text{Contract System Cost (CSC)}}{\text{Contract System Load (CSL)}}$$

Composition of Contract System Costs including Offsets



Contract System Cost Example

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses	$1,698,790,205	$1,038,411,122	$144,999,293	$515,379,790
Federal Income Tax Adjusted Return on Rate Base	$632,680,589	$342,140,154	$56,517,418	$234,023,025
State and Other Taxes	$196,302,665	$48,740,762	$8,461,008	$139,100,896
Total Other Included Items	$310,733,459	$213,853,258	$19,548,694	$77,331,506
Total Cost	$2,217,040,000	$1,215,438,780	$190,429,024	$811,172,204
(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)		$1,405,867,804		
(Less) New Large Single Load Costs (d)		$78,491,761		
(Less) Above-RHWM Load Costs (d)		$0		
Contract System Cost		$1,327,376,043		

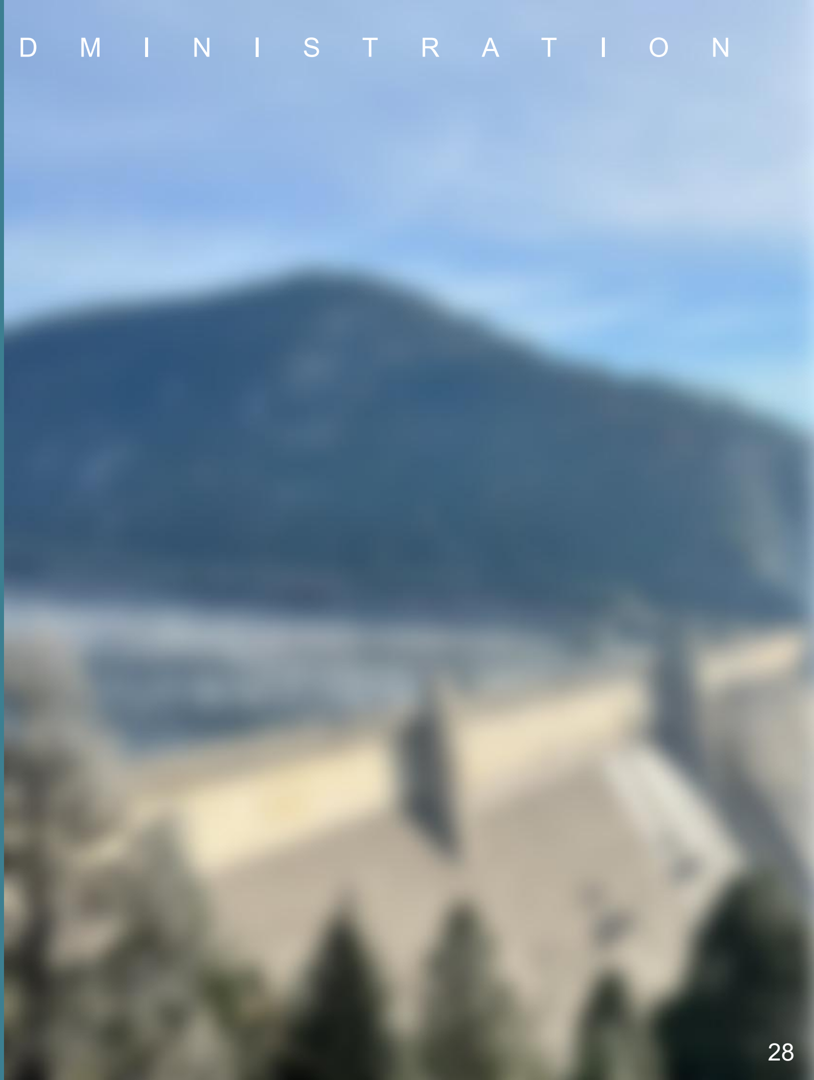
Contract System Cost represents all expenses, the approved return on rate base, all applicable taxes with a removal of power sales and various regulatory items. CSC is also reduced by the cost of serving an NLSL. The calculation only considers the Production and Transmission related values.

PART I:

ASCM and Appendix 1

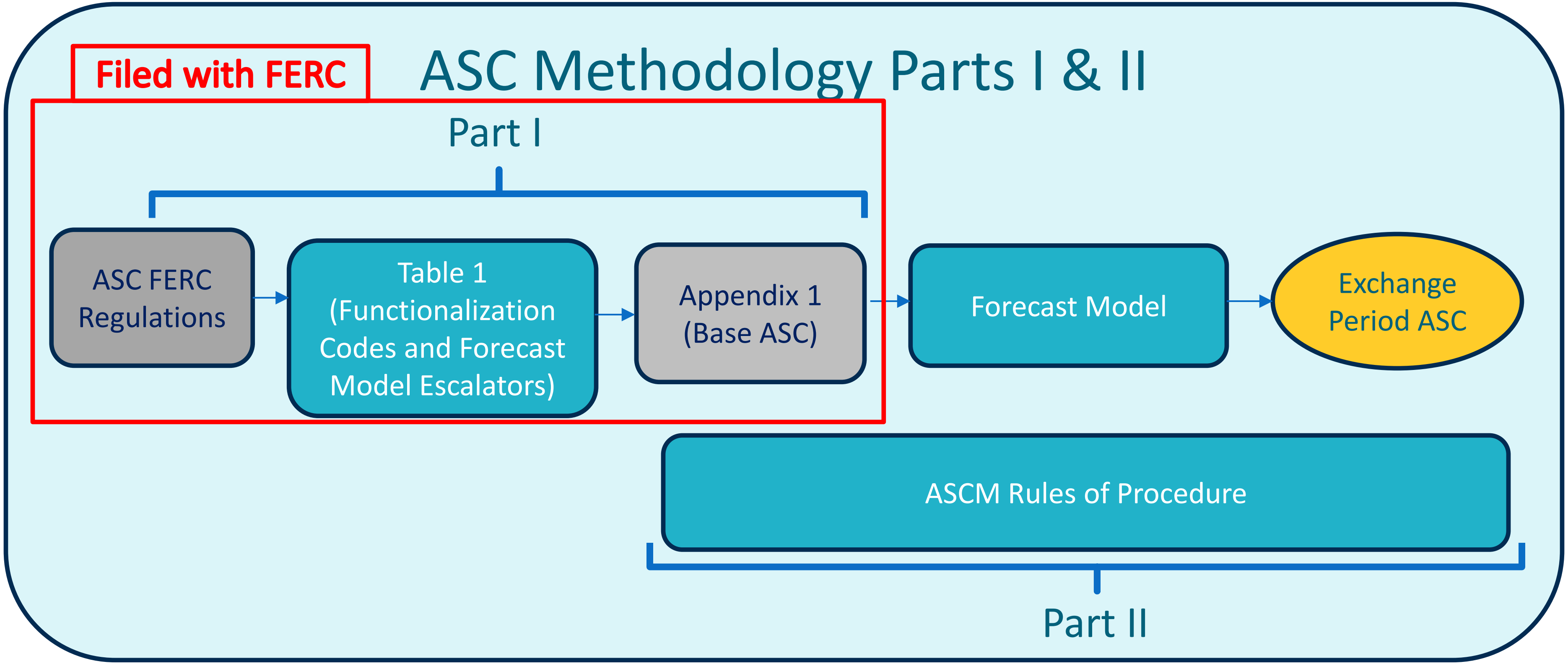
Presenters – Rich Greene and Michael Edwards

Senior Attorney-Advisor; REP Technical Lead



POST 2028 REP

ASCM Roadmap



ASCM Table 1

Table 1 provides a single reference for the following:

- FERC account numbers,
- Functionalization Codes
- Escalation Codes

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
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
Other Production	340-347	PROD		CONSTANT
Transmission Plant:				
Transmission Plant	350-359.1	TRANS		CONSTANT
Distribution Plant:				
Distribution Plant	360-374	DIST		CD

Excerpt from Table 1 – Schedule 1

ASCM Table 1: FERC Account Numbers

- FERC has adopted the "Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act." 18 CFR Part 101.
- The USoA organizes costs into various accounts, with direction on which costs are includable in each account.
- FERC Form 1 is an annual financial report with costs organized by FERC Account.

ASCM Table 1: Functionalization Codes

ASCM Section 301.7(b) lists the 10 Functionalization Codes used in the ASCM.

Three general methods to functionalize costs:

1) Entire Account functionalized to a single function.
   - PROD (Production); TRANS (Transmission); DIST (Distribution/Other)
   - E.g., Steam Power Fuel (501) uses PROD to functionalize all costs to Production.
2) Apply a functionalization ratio to an Account.
   - PTD (Production, Transmission, Distribution/Other Ratio); TD (Transmission, Distribution/Other Ratio); GP (General Plant Ratio); GPM (General Plant Maintenance Ratio); PTDG (Production, Transmission, Distribution/Other, General Plant Ratio); LABOR (Labor Ratio)
   - E.g., General Plant Land and Land Rights (389) uses PDT to functionalize portions to Production, Distribution, and Transmission (based on relative Plant).
   - E.g., Administration and General Salaries (920) uses LABOR to functionalize portions to Production, Distribution, and Transmission (based on relative Wages and Salaries).
3) Utility justifies functionalizing specific items in an Account to specific functions using direct analysis. There is a default Functionalization Code if the Utility does not justify a direct analysis.
   - DIRECT (Direct Analysis)
   - E.g., Intangible Plant – Miscellaneous (303) allows DIRECT analysis. If the Utility does not justify a direct analysis, the default functionalization is DIST (functionalized to Distribution/Other and excluded from ASC).

Appendix 1

- Costs from FERC Form 1 Accounts are entered and Functionalization Codes are applied in Appendix 1.
- This results in a Base ASC.

Account Description	FERC Form 1 Page Number	Functionalization Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other	Production	Transmission	Distribution/ Other
Schedule 1 Example											
General Plant:											
Land and Land Rights	204-207	389	PTD		55,658,942	24,202,929	5,616,107	25,839,906			
Structures and Improvements	204-207	390	PTD		26,598,435	11,566,157	2,683,839	12,348,439			
Schedule 3 Example											
Depreciation and Amortization:											
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	4,298,571			
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD	8,659,234	8,659,234	-	-	3,518,836		
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST	71,790,848	35,895,424	863,985	35,031,439	35,895,424	863,985	35,031,439

Forecast Model: Exchange Period Escalation

From the "Inputs" tab of the Forecast Model.

- Base year ASC data is escalated through the end of the exchange period, using each input's relevant Escalation Code from Table 1.
- Escalation factors are sourced from a 3rd party (see subsequent slide) excepting BPA's natural gas forecast.
- The escalated Base ASC is the Exchange Period ASC used to calculate REP benefits.
- Staff is not proposing any changes to assigned Escalation Codes.

2-Year Rate Case (Base+3, Base+4)

Calendar Year Escalators		Base+1	Base+2	Base+3	Base+4	Base+5
No Escalation	CONSTANT	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Plant	CD	9.13%	3.68%	0.24%	0.15%	0.17%
Inflation (GDP Price Deflator)	INF	2.67%	2.23%	0.22%	0.22%	0.23%
Wages	WAGES	2.29%	2.84%	0.31%	0.29%	0.27%
Steam Fuel - (Coal)	COAL	-6.51%	7.70%	1.23%	-0.37%	0.32%
Steam Operations	SOPS	2.42%	1.99%	0.22%	0.22%	0.25%
Steam Maintenance	SMN	2.54%	-1.01%	-0.01%	0.07%	0.10%
Nuclear Fuel	NFUEL	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear Operations	NOPS	2.08%	1.18%	0.13%	0.20%	0.23%
Nuclear Maintenance	NMN	2.13%	-0.68%	0.05%	0.12%	0.14%
Hydro Operations	HOPS	1.77%	1.06%	0.15%	0.22%	0.24%
Hydro Maintenance	HMN	2.08%	-1.11%	-0.02%	0.06%	0.09%
Other Fuel - (Natural Gas)	NATGAS	-63.24%	35.66%	6.38%	-1.85%	-0.53%
Other Operations	OOPS	2.57%	0.50%	0.09%	0.13%	0.15%
Other Maintenance	OMN	2.38%	-0.10%	0.02%	0.06%	0.08%
Transmission Operations	TOPS	1.72%	-0.46%	-0.05%	0.10%	0.15%
Transmission Maintenances	TMN	1.06%	-1.63%	-0.02%	0.07%	0.11%
Distribution Operations	DOPS	2.16%	0.20%	0.07%	0.18%	0.21%
Distributions Maintenances	DMN	0.34%	-2.00%	-0.04%	0.06%	0.10%
Customers Accounts	CACNT	3.39%	1.36%	0.03%	0.18%	0.24%
Customers Service	CSERV	2.60%	0.38%	-0.13%	-0.04%	0.19%
Customers Sales	CSALES	2.71%	1.62%	0.10%	0.16%	0.22%
Administrative and General	A&G	3.16%	2.14%	0.17%	0.21%	0.23%
Steam O&M	SOM	0.00%	0.00%	0.00%	0.00%	0.00%
Hydro O&M	HOM	0.00%	0.00%	0.00%	0.00%	0.00%
Other O&M	OOM	0.00%	0.00%	0.00%	0.00%	0.00%
Steam Plant	STMPLT	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear Plant	NUCPLT	0.00%	0.00%	0.00%	0.00%	0.00%
Hydro Plant	HYDPLT	0.00%	0.00%	0.00%	0.00%	0.00%
Other Plant	OTHPLT	2.49%	0.23%	0.08%	0.13%	0.16%
Transmission Plant	TRANPLT	1.94%	-0.09%	0.06%	0.13%	0.16%

*exemplative values

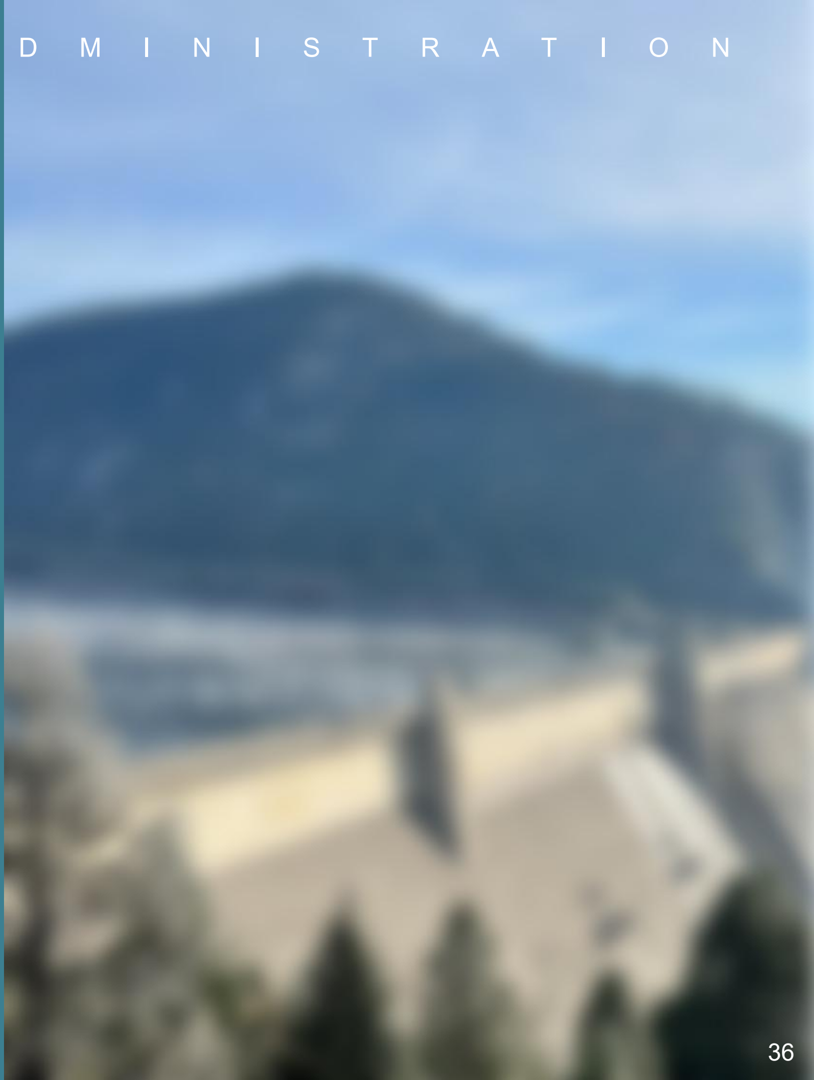
Forecast Model: Escalation Factors

A&G	Administrative and General
CACNT	Customer Account
CD	Construction, Distribution Plant
CONSTANT	Constant
CSALES	Customer Sales
CSERV	Customer Service
COAL	Coal
DMN	Distribution Maintenance
DOPS	Distribution Operations
HMN	Hydro Maintenance
HOPS	Hydro Operations
INF	Inflation
NATGAS	Natural Gas
NFUEL	Nuclear Fuel
NMN	Nuclear Maintenance
NOPS	Nuclear Operations
OMN	Other Production Maintenance
OOPS	Other Production Operations
SMN	Steam Maintenance
SOPS	Steam Operations
TMN	Transmission Maintenance

ASCM Structure

Presenter – Paulina Cornejo

REP Technical Lead



POST 2028 REP

2008 ASC Methodology FERC Reg.

Key Notes in following sections:

- **301.3 Filing Procedures** – Filing requirements to undergo the ASC Review Process. Guidelines housed in a separate document (Rules of Procedures).
- **301.4 Exchange Period ASC Determinations** – Stipulations for escalating Base Period ASCs to derive projected ASCs for the applicable Exchange Period.
- **301.5 Changes in ASCM** - BPA Administrator's discretion to initiate a new consultation process, and issues ASCM interpretations.
- **301.6 Appendix 1 Instructions** – Explains the purpose of the workbook and how to populate it for ASC determinations.
- **301.7 ASCM Functionalization** – The functionalization codes and application methods.

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.

2008 ASC Methodology FERC Reg.

- New table of contents
- ASCM divided into two parts

Structural Changes to 2008 ASCM

- Segregated ASCM into two parts:
  - PART 1: ASC FERC Regs, Table 1, Endnotes and Appendix 1 Template
  - PART 2: BPA's ASC Rules of Procedures and ASC Confidentiality Rules
- Clarifying the calculation of Base Period ASCs and Appendix 1 instructions.
- Endnotes, as references, were moved to Table 1, instead of Appendix 1.
- Moved the substantive text from 2008 Endnotes to the body of the ASCM in section 301.4 – Base Period ASC.

Endnotes Moved to ASCM Body

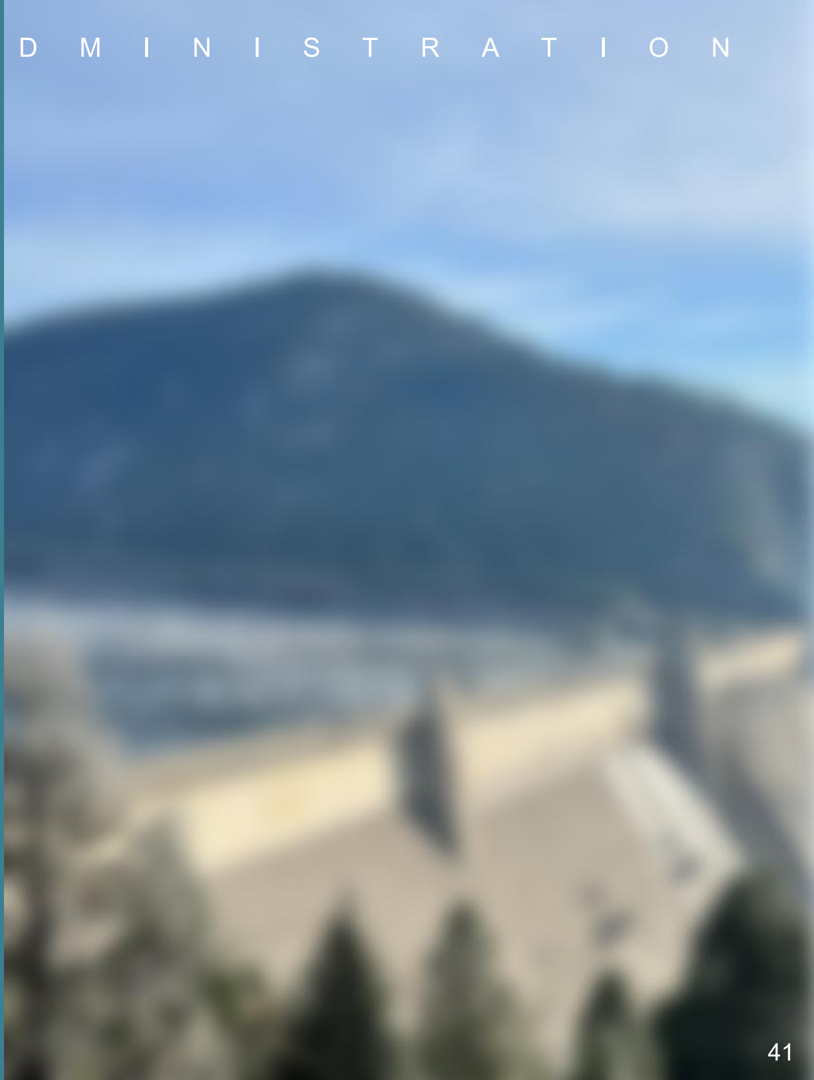
Endnote from 2008 ASCM	Substantive text moved to….
b/Rate of Return	All moved to ASCM Section 301.4: Base Period ASC
c/Tax-exempt Utilities	
d/NLSL treatment	
e/Distribution Losses calculation	
f/Cash working capital	
g/Conservation costs	
h/Public Purpose Charges	
i/FERC Order 888 on Transmission expenses	

ASCM

Proposed to Carry Forward and Update

Presenter – Michael Edwards

REP Technical Lead



Proposed to Carry Forward from 2008 ASCM

- FERC Form 1 (FF1) as the source data to populate the Appendix 1 and make ASC determinations.
- Base Period ASCs to Exchange Period ASCs.
  - Continue to set Base Period ASCs on historical FF1 data and escalate forward to feed calculation of projected ASCs for the applicable Exchange Period.
- Major resource additions and removals.
  - Materiality thresholds remain the same.
- Rules of Procedures:
  - ASC Review Processes filing requirements, procedural events and schedule.
  - Confidentiality Rules
- Table 1: Functionalization and Escalation Codes remain unless otherwise proposed.

Proposed Updates to ASCM Sections

- Federal Income Taxes in Rate of Return Calculation
- Distribution Losses calculation
- Mid-point Exchange Period averaging
- Removing Above-RHWM and COUs references
- FERC Account removals and additions

Federal Income Taxes in Rate of Return

- Endnote b/ describes the Rate of Return calculation in which the Federal Income Tax rate is a component.
- This Endnote was moved to the ASCM body.
- Added clarifying language around the applicable Federal Tax Rate.

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

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

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.

Distribution Loss Calculation

- Endnote d/ describes three methods to calculate a REP-utility's distribution loss factor.
- Staff proposing to pare down the methods to only Method 3.

e/ The losses shall 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 as follows ~~can be measured using one of the following 3 methods~~:

~~*Method 1, Distribution Loss Study:* Losses shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall 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 shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops~~

~~*Method 2, Revenue Grade Meters:* If a Utility does not have a loss study, but it has sufficient revenue grade meters in its distribution system, BPA will permit the Utility to directly measure its distribution losses subject to BPA review and approval. A Utility that does not possess the capability to directly measure its distribution losses will be required to submit a distribution loss study every seven years.~~

~~*Method 3, Default:* If a Utility does not have a current loss study or grade meters, BPA will accept the following method for determining a Utility's distribution loss factor.~~

i. 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. COUs will use a comparable data source.

ii. From this 5-year total system loss factor, subtract ~~the loss factor for~~ BPA's 12-month weighted average transmission system loss factor.

iii. 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.

Midpoint Exchange Period Averaging

Clarify averaging to the Midpoint of the Exchange Period in the Forecast Model using one of two methods.

- Method 1: Average forecasted start and end date ASCs.
- Method 2: Use the ASC forecasted to the midpoint of the exchange period.

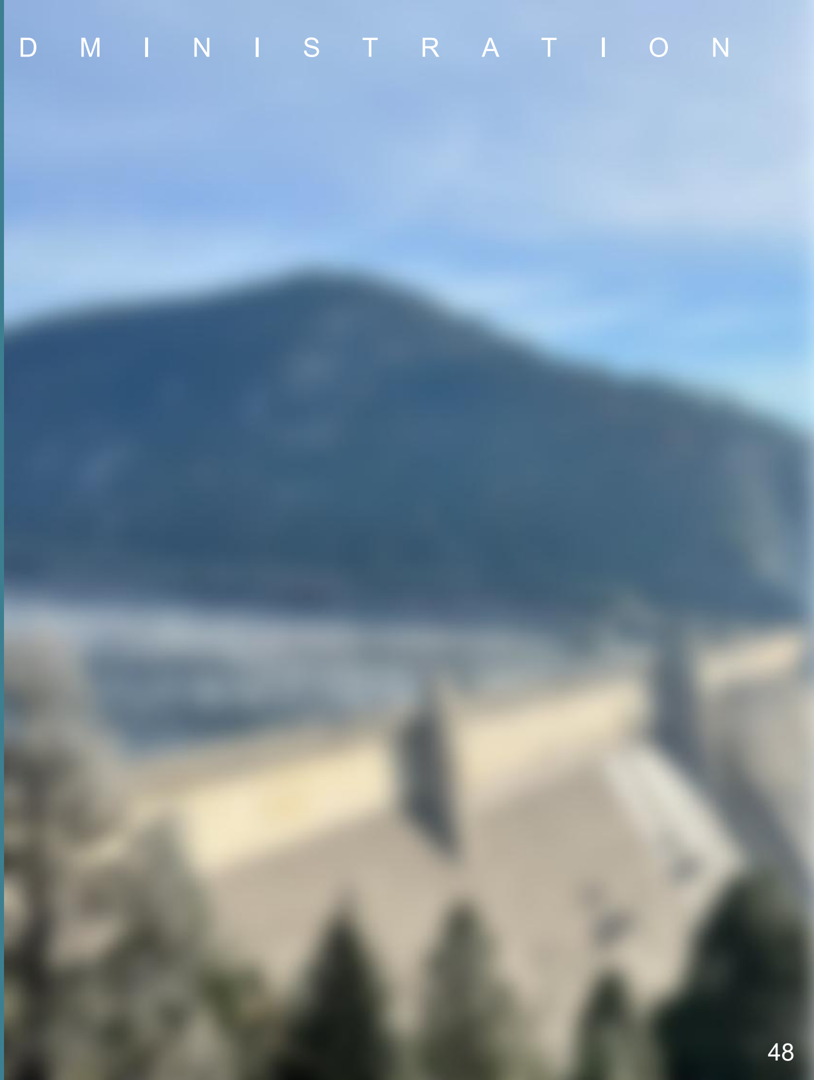
Removing Above-RHWM and COU References

- A provision under the Provider of Choice contracts waives the Publics' participation in the REP.
- As such, references and provisions to the following terms have been removed throughout the ASCM:
  - Consumer-owned Utility, Net Requirements, Priority Firm Power, Rate Period High Water Mark Process (RHWM Process), RHWM Exchange Load, RHWM System Resources, Tier 1 Priced-Power, Tier 1 System Resources, and Tiered Rates Methodology

FERC Account Updates

Presenter – Scott Winner

REP Manager



FERC Account Adds and Removals

- BPA is proposing to remove the following accounts as they are no longer listed on the FERC Form 1:
  - Account 108, Mining Plant Depreciation
  - Account 108, Leasehold Improvements
  - Account 906, Customer Service
  - Account 933, Transportation (Non-Major)

Schedule 1. Renewables

- Utilities have been reporting these Production cost to Accounts 340 – 347, Other Production.
- BPA proposes adding the below Accounts to the Table 1, functionalized to Production:
  - Solar Production, 338.1 – 338.13
  - Wind Production, 338.20 – 338.34
  - Other Renewable Production, 339.1 – 339.13

Schedule 1. Account 108

- The following Table 1 entries from the Account 108 table are no longer listed on the FERC Form 1:
  - Mining Plant Depreciation
  - Leasehold Improvements
- BPA is recommending removing them from Table 1.

Schedule 3. Customer Service

- Currently Table 1 requests Customer Service and Information, Accounts 906-907. Account 906 is no longer on the FERC Form 1.
- BPA proposes removing Account 906 from Table 1.

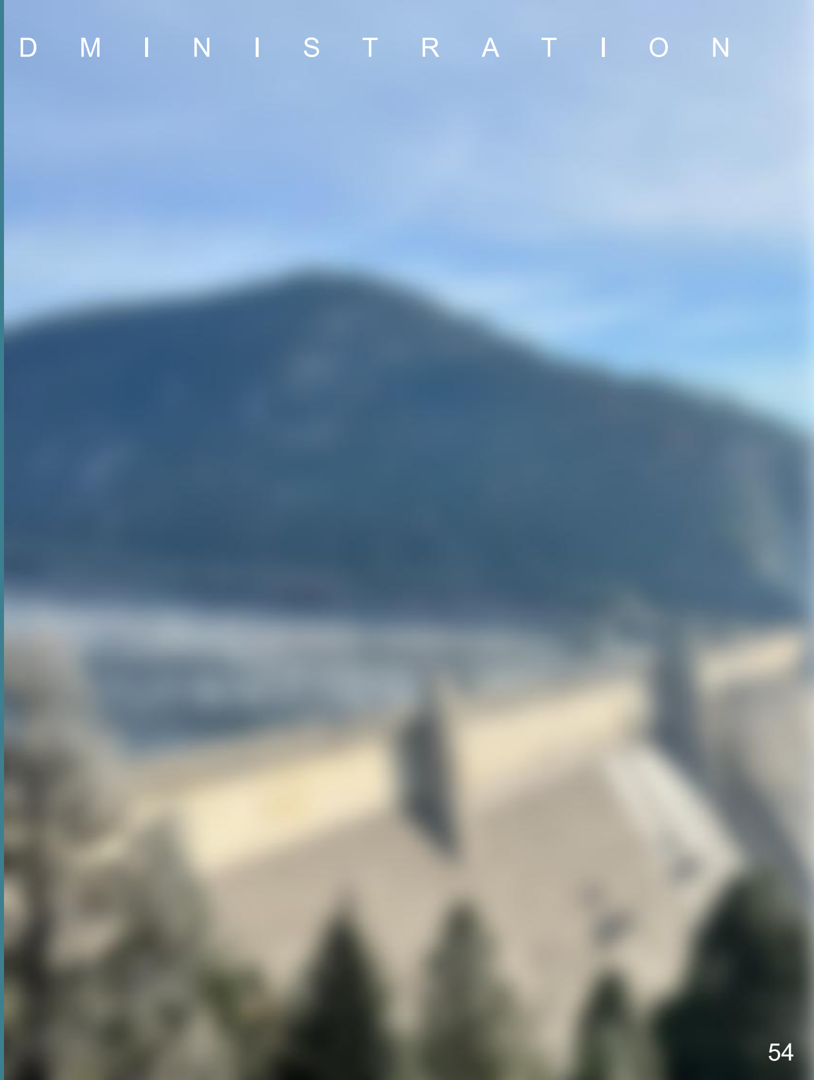
Schedule 3. Transportation

- Currently Table 1 requests information for Account 933, Transportation (non-Major). This account is no longer on the FERC Form 1.
- BPA proposes removing Account 933 from Table 1.

Functional Overview of Appendix 1

Presenter – Michael Edwards

REP Technical Lead



Functional Overview of Appendix 1

- The purpose of the Appendix 1 is to supply all the data, specific to the exchanging utility, necessary to calculate the Base Period ASC and Exchange Period ASC; by way of the ASC Forecast Model.
- Appendix 1, as proposed, will continue to be sourced largely from FERC Form 1.

Functional Overview of Appendix 1

Sch 1 & 1A: Rate Base & Cash Working Capital

Net Plant (less depreciation & amortization)

Assets & Other Debits (including Cash working Capital) Less Liabilities & Credits

Cash Working Capital:

One-Eighth of revised Total O&M Expenses

Sch 2: Rate of Return

Return on Equity

Cost of Debt

Federal Income Tax

Product of Rate Base and ROR is included in Total System Costs(CSC)

Sch 3, 3A, & 3B: Expenses, Taxes, & Other Items

Expenses

Taxes: Federal, State, & Other

Other: Regulatory Debits & Credits, Disposition of Plant, Disposition of Allowances, Sales for Resale, Other Revenues.

Sch 4: Average System Cost

The other Schedules feed to Schedule 4

Contract System Cost over Contract System Load = ASC

NLSLs

Functional Overview of Appendix 1

3-Year PP & OSS

Base year and two previous calendar years of power purchases and sales. Weighted 3-2-1 starting with the base year. Serves as an input into the OSS & PurPwr Forecast (purchase & sales forecast) in the Forecast Model.

Load Forecast

Spans the base year through four years past the exchange period for both Contract System Load and Exchange Load.

Distribution Calculation

Three current methods are:

1. Distribution Loss Study
2. Revenue Grade Meters
3. Default Calc

Salaries

Labor Ratio inputs, consisting of salaries and wages related to Electric Operation and Maintenance.

Functional Overview of Appendix 1

Ratios

Labor

GP - General Plant

PTD – Production, Transmission, Distribution

PTDG – Production, Transmission, Distribution, & General Plant

TD – Transmission & Distribution

GPM – Maintenance of General Plant Ratio

New Resources

Resources coming online after the base year, filing of AP1.

Threshold of 2.5% Overall (0.5% individual & 2.5% group change in ASC)

New Large Single Loads

The cost of additional resources sufficient to serve any New Large Single Load (NLSL) that was not contracted for, or committed to, prior to September 1, 1979…

Updates to Appendix 1 Schedules

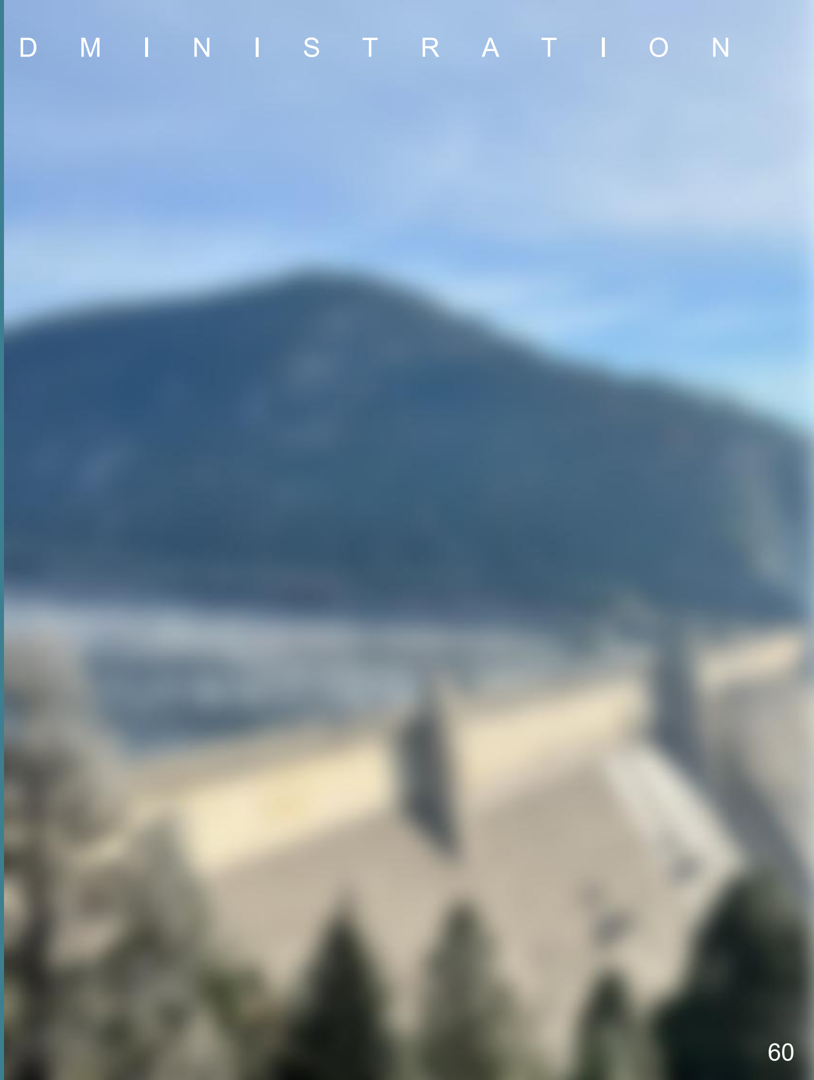
Staff has made updates to the following Schedules and tabs in the Appendix 1, which will be covered in Workshop 3 on Nov. 20th.

- Schedules: 1, 2, 3, 3B, 4
- Load Forecast Tab
- 3-Year PPS & OSS
- New Resources and Materiality Tabs
- Removal of A-RHWM and Tiered Rate Tabs
- NLSL Rate Tab

Rules of Procedure

Presenter – Michael Edwards

REP Technical Lead



What are the Rules of Procedure?

- Define the ASC Review Process to determine utilities' ASCs for REP benefit calculation.
  - Establishes timeframes and schedule of events.
- Outline the utilities' filing requirements under the ASC Review Processes, as well as the off-year filings which are coined Informational Filings.

Proposed to Carry Forward-Timeline of Process

- ASC Review Process
  - Review of Utilities' ASC Filings
  - Discovery
  - Issue Lists
  - Clarification Workshops
  - Draft ASC Reports
  - Oral Argument
  - Final ASC Reports:
    - Finals ASCs and PFx Rates
    - REP benefits for Exchange Period

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 Appendix 1 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.

ASC Filing Requirements – 2012

SECTION 2. FILING PROCEDURES (ASC REVIEW PROCEDURES)

2.1 Exchange Period Filing Requirements

2.1.1 The Exchange Period will be equal to the term of BPA's Rate Period. ASCs will change during the Exchange Period only for the reasons provided in 18 C.F.R. § 304.1.

2.1.2 Utilities shall upload to BPA's Secure REP website at least one "ASC Filing," which shall include two Excel models, the Appendix 1 workbook and the Forecast Model, and all supporting documentation used to prepare the ASC Filing, by the later of (i) June 1 of each year or (ii) the deadline identified on the ASC Review Process Schedule posted on the Residential Exchange Program website. In years when BPA is not conducting a formal review process (Formal ASC Review Process), these filings shall be for informational purposes only, include only the Appendix 1 Excel workbook, and shall not change a Utility's ASC. For investor-owned utilities, the ASC Filing shall be based on the Utility's most recently filed FERC Form 1 and limited information from prior FERC Form 1 filings, as required. For consumer-owned utilities, the ASC Filing shall be based on the Utility's most recent audited financial information. BPA may request that consumer-owned utilities provide a cost of service analysis with their ASC Filings. For the Formal ASC Review Process only, each ASC Filing shall contain an attestation signed by a senior financial officer of the Utility substantially similar in form to Attachment A.

ASC Filing Requirements – 2026

- Exchange Period Filing Requirements
  - Fully Populated Appendix 1 workbook
  - Supporting documentation, studies, and analysis used to prepare the Appendix 1
  - The Utility's pre-run Forecast Model
  - A variance analysis, which includes columns for the current Appendix 1 inputs, the prior Appendix 1 inputs, and the percentage increase or decrease
  - An attestation, following the template included in Attachment A, signed by a senior financial officer of the Utility stating that the filing has been compiled in accordance with the Commission's Uniform System of Accounts, the ASC Methodology, and Generally Accepted Accounting Principles, and is consistent with applicable orders and policies of the Utility's Regulatory Body
  - Participation forms: Petition to Intervene, Consent to be Bound and Confidentiality forms

Information Filings

- As part of the 2028 RPSA, the Informational Filings will be biennial requirement.
- Updated language to reflect this change.

2.1.3 **Informational Filings:**
In years when BPA is not conducting an ASC Review Process, an Appendix 1 Filing, Utilities are required to submit an Informational Filing that will not change a Utility's ASC. The Appendix 1 data shall be based on the Utility's most recently filed FERC Form 1 and limited information from prior FERC Form 1 filings as required.

Proposed to Carry Forward – Additional Items

- Senior Financial Officer Attestation

Attachment A

Senior Financial Officer Attestation

<<Customer's Name>>
Average System Cost Filing
For the Base Period Beginning ___________, 20XX
And Ending ___________, 20XX

I, ________________________________, having reviewed the Average System Cost (ASC) Appendix 1 Filing (ASC Filing) attached with this attestation, hereby certify that:

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

2. The 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 ASC Filing, if any.

4. Based on my knowledge as <<Customer's Name>>'s Senior Financial Officer, the ASC Filing is based on <<Customer's Name>>'s audited financial statements, FERC Form 1 filings for IOUs and Annual Reports and most recent Cost of Service Analysis (COSA) for COUs, 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 ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Senior Financial Officer
<<Customer's Name>>

Date:_______________

Proposed to Carry Forward – Additional Items

- ASC Confidentiality Rules
  - Updated date & title change but proposing to keep Attachment 1: Consent To Be Bound unchanged.

ATTACHMENT 1

CONSENT TO BE BOUND FORM

Docket Nos. [List all that apply]

I. Consent to be Bound

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 Proceedings.

By: ______________________________ ______________________________
Signature Date

______________________________ ______________________________
Print Name Title

II. Persons Qualified Pursuant to Sections 2.2.3 and 4.2.3

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

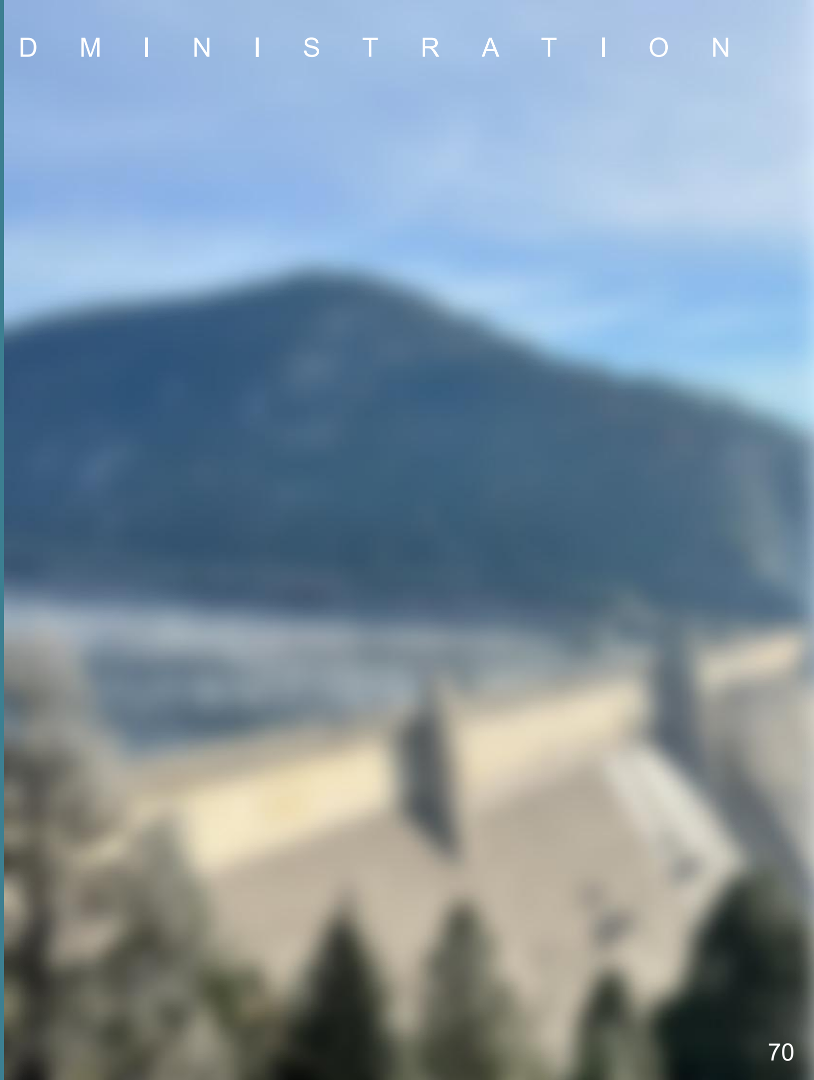
By: ______________________________ ______________________________
Signature Date

Excerpt from Consent to Be Bound Form

ASCM Topics for Workshop 2

Workshop 1: Oct. 23rd	Workshop 2: Nov. 5th	Workshop 3: Nov. 20th	Workshop 4: Dec. 3rd
• ASCM Structure • ASC Review Process and Rules of Procedures • Sections Carried-Forward • Updates to FERC Accounts and ASCM Sections • Functional Overview of Appendix 1 and Forecast Model • WS 2 Topics	Topics: • Transmission Costs • Injuries and Damages (Account 925) • Energy Storage Devices More ASCM Proposals: • Calculation of NLSL Costs • Source of Escalation Data • Meeting Load Growth	• Wrap-up pending topics from WS 1 and 2 • Revisions to the Appendix 1 Template and Forecast Model • Customer-led Topics	• Discussion is focused on Preliminary ASCM Draft

Q&A



Close-out

Presenter – Scott Winner

Power Planning and Forecasting Supervisor

POST 2028 REP

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

Attachment 3
BPA ASCM Presentation
December 3, 2025

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Post-2028 Residential Exchange Program Average System Cost Methodology Workshop

Wednesday, December 3rd, 2025

9:00 am – 4:00 pm

RHR and WebEx

POST 2028 REP

December 3rd Workshop Agenda

Workshop #1 Topics	Presenter(s)
Introductions and Agenda	Scott Winner
Updated Phase Schedule	Scott Winner
Rules of Procedure and Confidentiality Rules	Paulina Cornejo
Transmission Costs	Richard Greene
Injuries and Damages, Account 925	Neal Gschwend
Energy Storage Plant	Neal Gschwend
New Large Single Loads	Paulina Cornejo
Escalation Factors	Michael Edwards
Meeting Load Growth for ASC Determination	Michael Edwards
Summary of Proposed Carry Forwards and Changes	Paulina Cornejo
Closeout	Scott Winner
Breaks	**Est. Times**
LUNCH	Noon – 1:00 pm

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

ASCM Workshop 2 Topics

Workshop 1: Oct. 23rd

- ASCM Structure
- ASC Review Process and Rules of Procedures
- Sections Carried Forward
- Updates to FERC Accounts and ASCM Sections
- Functional Overview of Appendix 1 and Forecast Model
- WS 2 Topics

Workshop 2: Dec. 3rd

- Phase 2 Schedule Changes

Proposed Changes:

- Transmission Costs
- Injuries and Damages (Account 925)
- Energy Storage Plant
- Treatment of NLSLs
- Source of Escalation Data
- Meeting Load Growth

Preliminary ASCM Release: Dec. 10th

- BPA releases Preliminary ASCM Draft for informal comment.
- Regional parties submit informal comments to the REP2028@bpa.gov inbox.

Workshop 3: Dec. 16th

- Questions on WS 1 and 2 Content
- Walkthrough entire ASCM
- Walkthrough Appendix 1 Template and Forecast Model
- Customer-led Topics

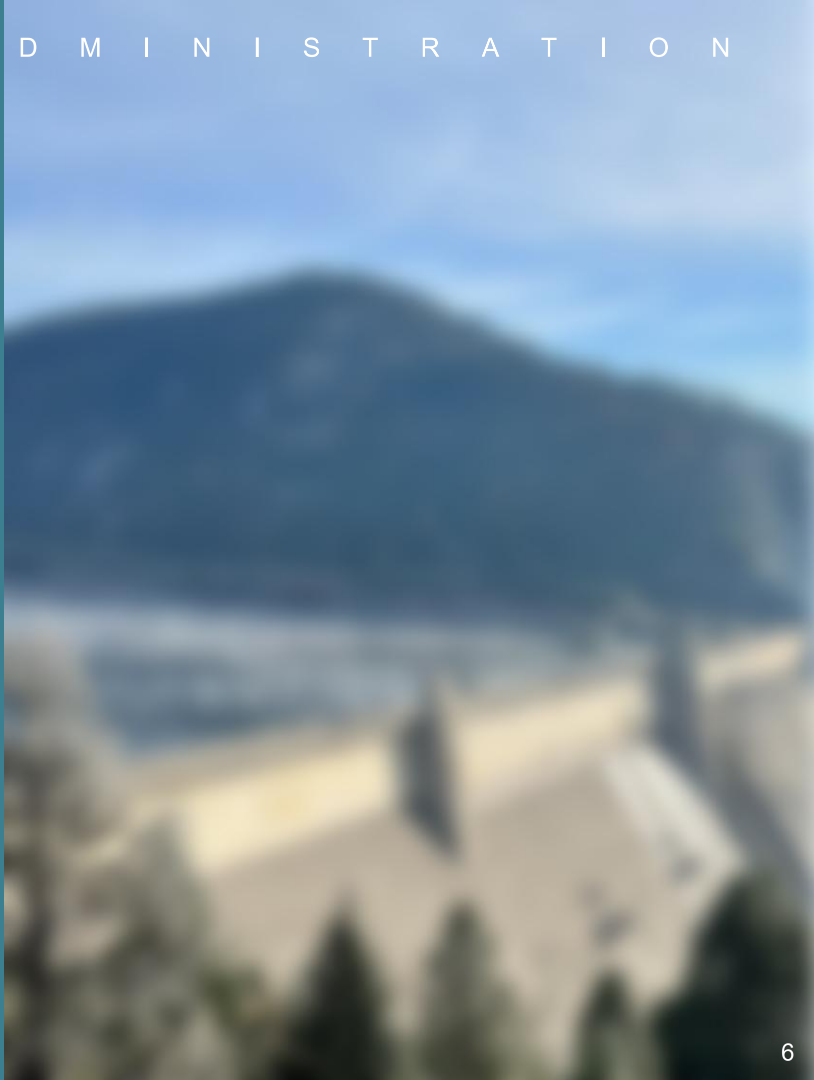
Phase 2 Schedule Update

Date	RPSA	ASCM
Nov 25, 2025, Tue	**Comments due**, Preliminary	
Dec 3, 2025, Wed		WS2
Dec 9, 2025, Tue	**Post**, Full	
Dec 10, 2025, Wed		**Post**, Preliminary
Dec 16, 2025, Tue		WS3
Jan 21, 2026, Wed	**Comments due**, Full	**Comments due**, Preliminary
Feb 3, 2026, Tue		**Post**, Full
Mar 6, 2026, Fri	ROD	
Mar 9, 2026, Mon		**Comments due**, Full
Apr 24, 2026, Fri		ROD
Late Jul 2026		FERC Interim Approval

Rules of Procedure and Confidentiality Rules

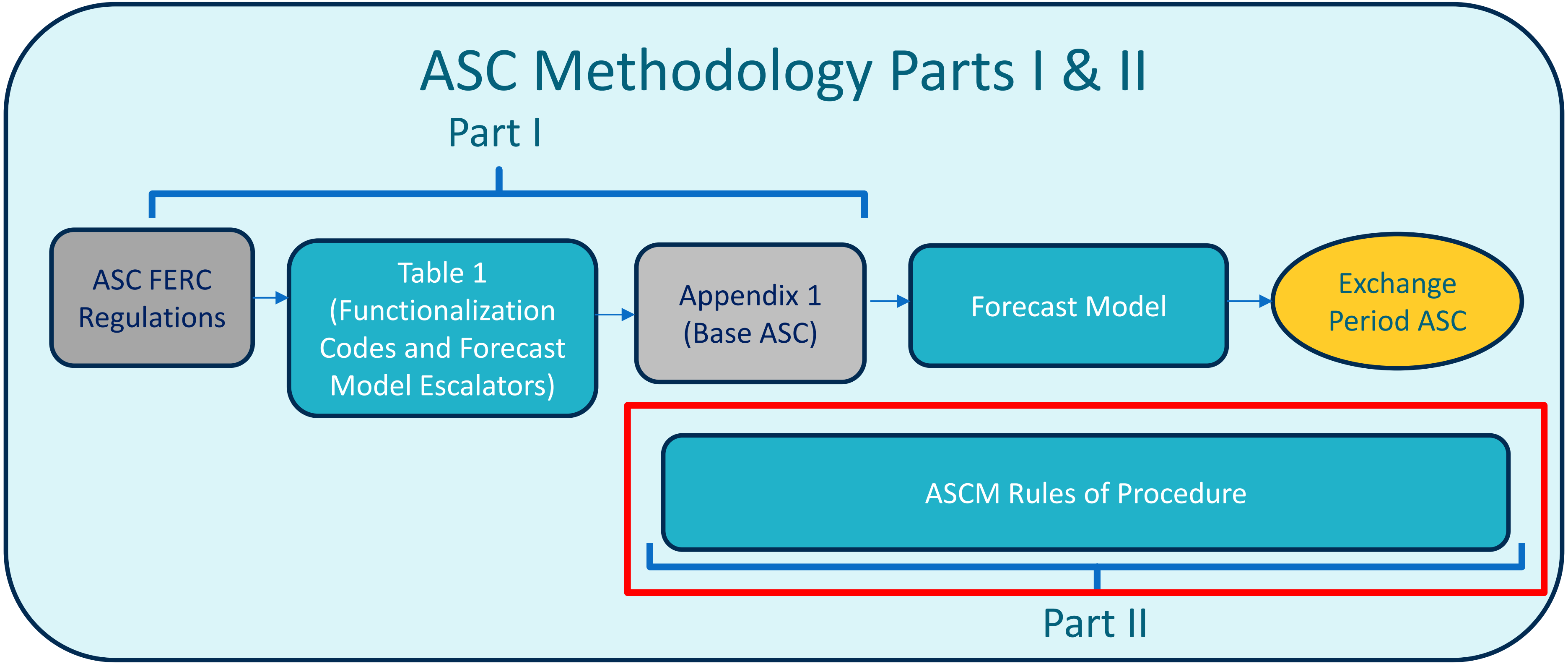
Presenter – Paulina Cornejo

REP Policy Lead



POST 2028 REP

ASCM Roadmap



Changes from Workshop 1

- After the ASCM workshop on Oct. 23rd, BPA made additional proposed revisions to the Rules of Procedure to further clarify the procedural requirements.
- Additionally, we revised the Confidentiality Rules and embedded them in the Rules of Procedure as Attachment B.
- A redline of the document to crosswalk the changes will be included in the release of the preliminary full draft.

Rules of Procedure Primary Changes

- Substantive proposed changes are as follows:
  - Section 2 – Filing Procedures
    - Clarified requirements for ASC Filings for ASC Review Process vs Informational ASC Filings.
    - Updated provisions for non-submittal and deficient filings.
  - Section 3 – ASC Review Process
    - Modernized procedural requirements of the ASC Review process.
    - Removed section 3.7.2.2 which discusses the instance BPA does not publish Final ASC Reports.
  - Attachment A – Senior Financial Officer Attestation
    - Removed references to COUs and added Base Period to ASC Filing.

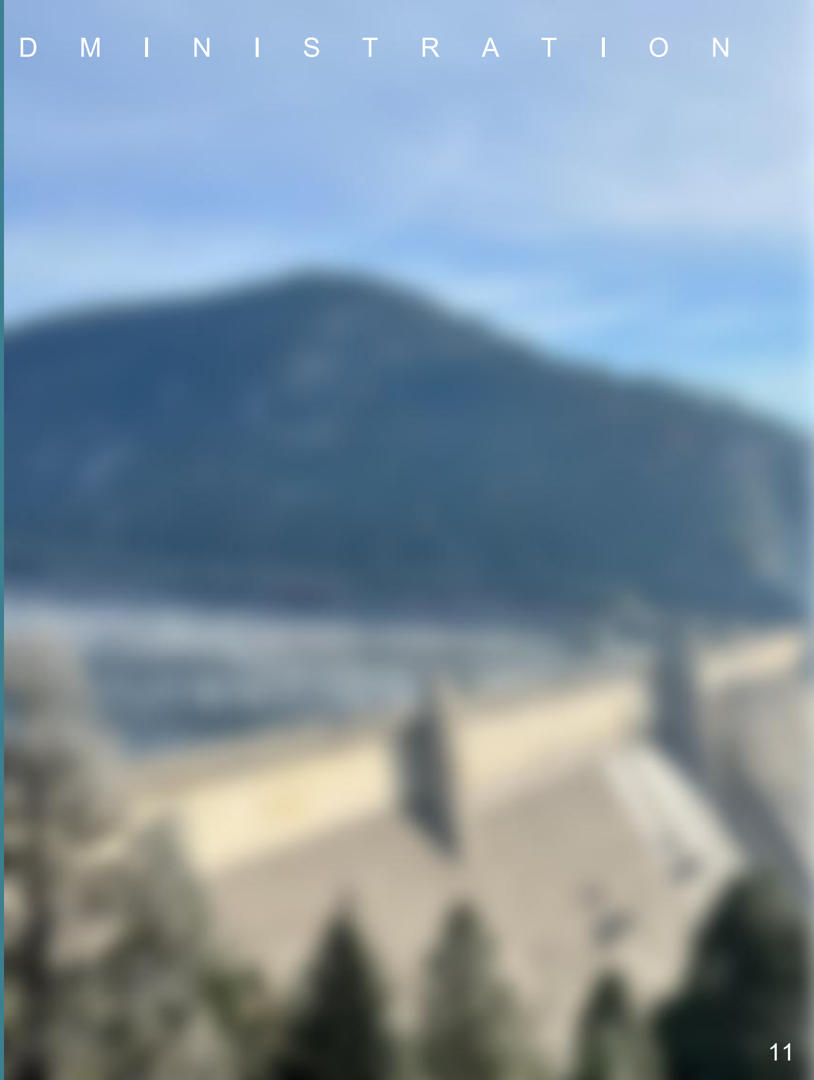
Confidentiality Rules Primary Changes

- Redline edits sprinkled throughout the document, but substantive proposed changes are as follows:
  - Added the document as Attachment B to the Rules of Procedure.
  - Renamed the "Consent to be Bound" form to "Confidentiality Agreement".
    - Utilities that sign this agreement adhere to the rules protecting confidential information shared as part of the ASC Review Processes.

Transmission Costs in ASC

Presenter – Richard Greene

Senior Attorney-Advisor



POST 2028 REP

Transmission Costs in ASC

- Statutory Underpinnings
  - Section 5(c)(1)

    Whenever a Pacific Northwest electric utility offers to sell **electric power** to the Administrator at the **average system cost of that utility's resources** in each year, the Administrator shall acquire by purchase **such power** and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.
  - Section 5(c)(4)

    An electric utility may terminate, upon reasonable terms and conditions agreed to by the Administrator and such utility prior to such termination, its purchase and sale under this subsection if the supplemental rate charge provided for in section 839e(b)(3) of this title is applied and the cost of electric power sold to such utility under this subsection exceeds, after application of such rate charge, the **average system cost of power sold** by such utility to the Administrator under this subsection.
  - Section 5(c)(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.

Transmission in Previous ASCMs

- 1981 ASCM –
  - BPA sold bundled power/transmission in one rate.
  - ASCs included all Utilities' Transmission Costs.
  - BPA did not provide legal analysis of decision; considered a settled methodology.
  - COUs participated in REP exchanging only transmission costs.

Transmission in Previous ASCMs

- 1984 ASCM –
  - Found there was no legal requirement to include transmission costs in ASC.
  - Transmission costs were permissible as a matter of “policy”.
  - BPA allowed existing transmission costs into ASC; future transmission costs allowed in only if needed for generation integration.

Transmission in Previous ASCMs

- 1996 – BPA unbundled Power and Transmission rates.
- 2000 – BPA developed separate Power and Transmission revenue requirements, repayment studies.
  - Power customers hold transmission contracts with BPAT and pay transmission rates for the recovery of the FCRTS costs.

Transmission in Previous ASCMs

- 2008 ASCM
  - Reiterated that transmission not required to be in ASC.
  - Allowed all transmission costs back into ASC as a matter of policy, identified policy reasons for the change.
- 7(b)(2) Rate Test Implications
  - PFx Rate does not include transmission costs.
  - BPA *includes* BPA's NT transmission costs when developing its rates to determine cost/benefits of REP.
  - BPA *excludes* BPA's NT transmission costs from ASC to run Section 7(b)(2).

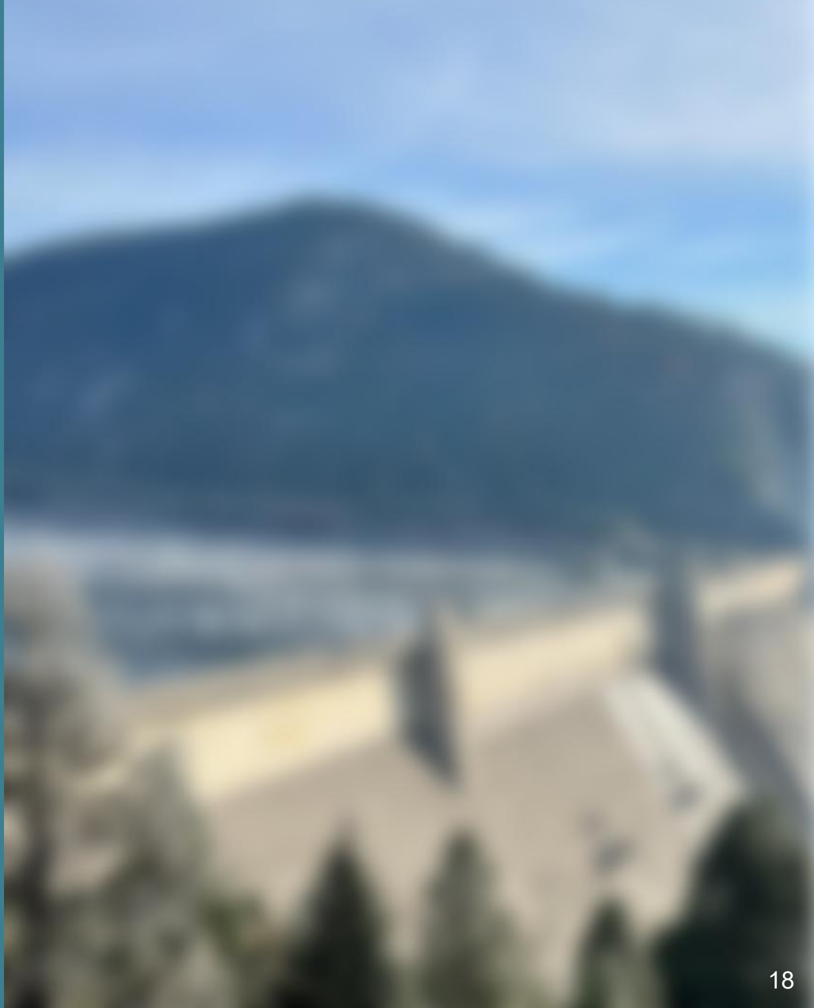
Proposal for 2026 ASCM

- Remove all transmission costs from ASC, except for:
  - Third-party wheeling transmission costs (Account 565).
  - Transmission associated with Sales for Resale (Account 447).
    - BPA assumes the Sale for Resale credit is lower as a result of transmission (delivery) costs.
    - BPA will add a line item to the Appendix 1 for additional transmission costs associated with Sales for Resale not otherwise accounted for in Account 447.
    - Utility must provide documentation to support inclusion of additional transmission costs with Account 447, subject to BPA review.
  - These "transmission" costs are equivalent to the costs BPA Power recovers in the PF rate.
- Reasoning
  - Ties better to the statutory language.
  - Implementation of section 7(b)(2) is cleaner.
  - Ensures REP benefits paid based on actual generating resource costs, rather than increased transmission costs.

Injuries and Damages (925)

Presenters – Neal Gschwend

Attorney-Advisor



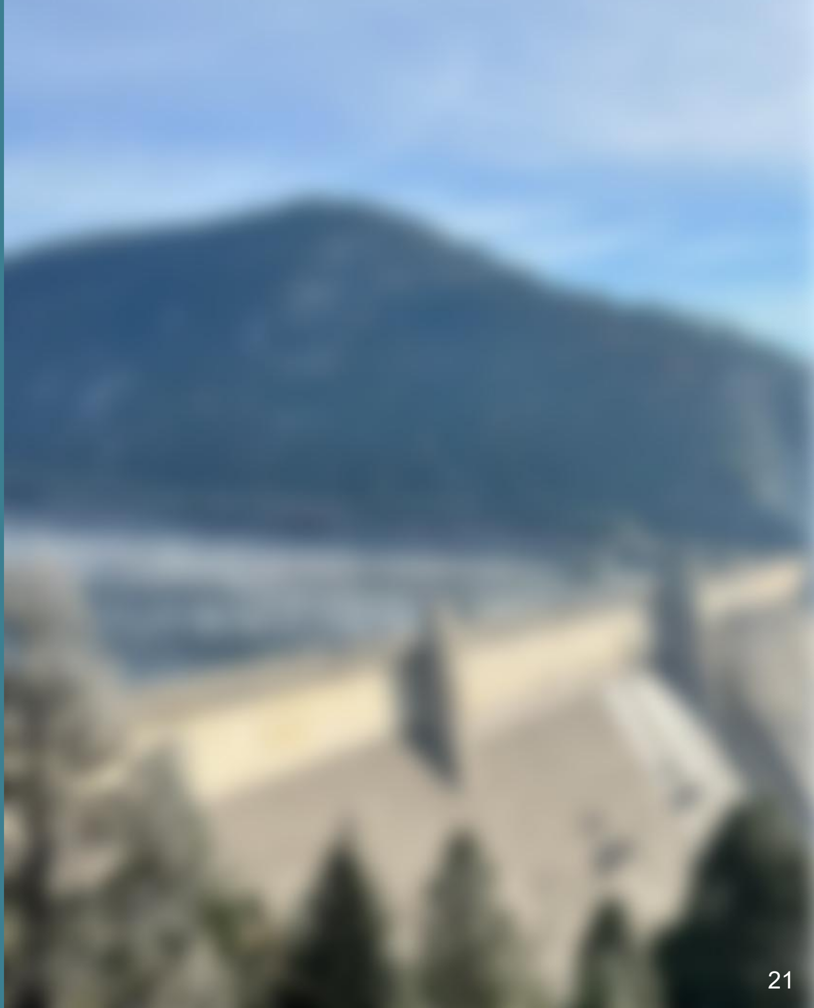
POST 2028 REP

Injuries and Damages – Background

- Current ASCM treats Account 925 as a direct input, with Labor Ratio functionalization to Production/Transmission/Distribution.
- These amounts can be large, and it appears state commissions do not uniformly allow them as a direct input to be recovered in rates.
  - For example, a regulatory body might allow 50% to be recovered over 20 years, rather than 100% in a single year.
  - This could cause a large disparity between a Utility's ASC and its retail consumers' rates.

Injuries and Damages – Initial Proposal

- Rely on Regulatory Body expertise.
  - While the current ASCM largely moved away from the jurisdictional approach to the FERC Form 1 approach, the current ASCM still relies on state commissions for fact-intensive, policy-laden issues like Return on Equity, regulatory assets and liabilities, and public purpose charges.
- To include Account 925 injuries and damages:
  - Account 925 functionalized to DIST/OTHER.
  - Replaced by a new input where the Utility submits state orders specifying amounts of Account 925 costs approved for retail rate recovery during the Base Period.
  - Total amount subject to Labor Ratio (same as current ASCM re 925).
  - ASCM will not allow double recovery of these costs housed in other accounts (e.g., Regulatory Assets or Liabilities).



Energy Storage Plant (387)

Presenter – Neal Gschwend

Attorney-Advisor

Energy Storage Plant – Background

- FERC Order 898 revised accounts for Energy Storage Plant.
  - Used to have separate accounts for each function (348, 351, 363)
  - Now a single set of "Energy Storage Plant" accounts (387-387.12)
- The ASCM will need to functionalize these costs to Production, Transmission, and Distribution/Other.

Energy Storage Plant – Background

- Batteries can serve multiple uses, and there is not a clear rule for functionalizing their costs. Batteries might be used for, e.g.:

Arbitrage	Peak Shaving
Firm Capacity	Operating Reserves
Ancillary Services	Deferring Transmission Investments
Deferring Distribution Investments	Advanced microgrid setup
Reduce end-use consumer demand charges	Black Start

- FERC has approved Storage as Transmission-Only Asset (SATOA).
- Batteries may appear uneconomical compared to other Production technologies, but may be justified by a unique combination of values.
  - Cost causation might lead to recovering such costs from different functions.
- How a Utility chooses to use a battery may change over time.
- Regulatory bodies may apply a case-by-case analysis of use and cost-causation.

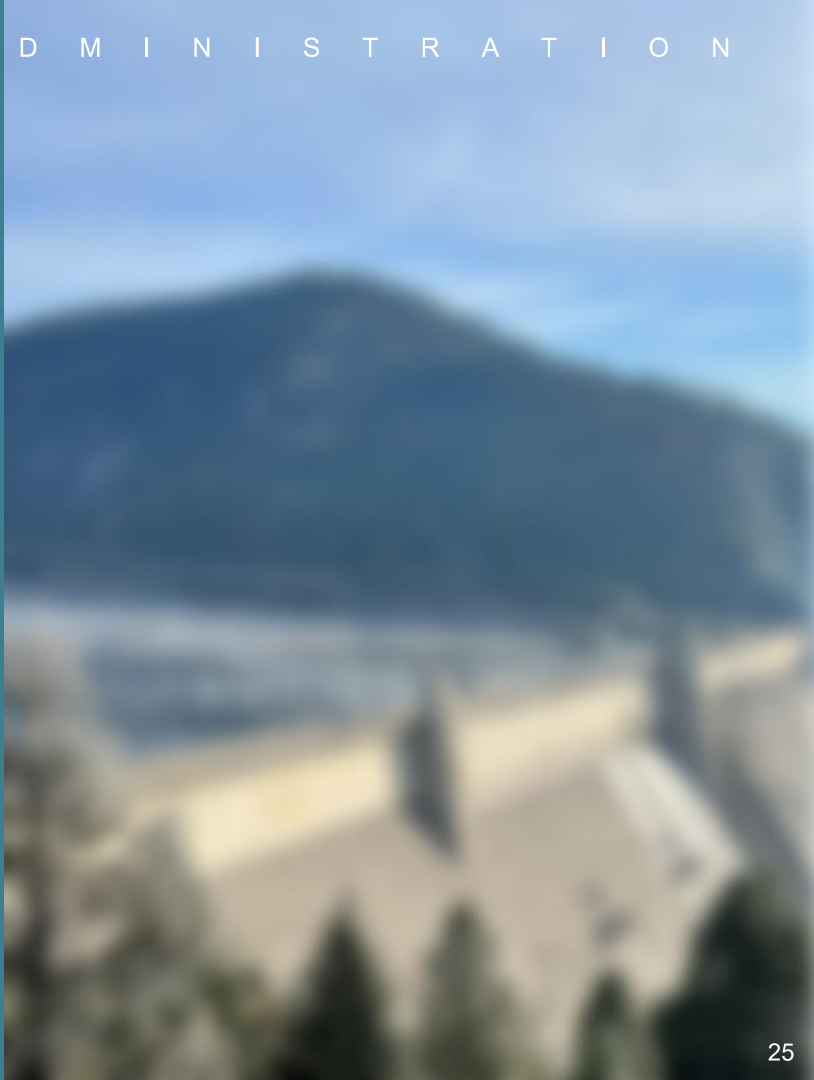
Energy Storage Plant – Initial Proposal

- Functionalize Accounts 387-387.12 using the PTD (Plant) ratio.
- Given the dynamic nature of the technology and industry, BPA Staff were concerned attempts at a more precise functionalization methodology would not age well.

New Large Single Loads

Presenter – Paulina Cornejo

REP Policy Lead



NWPA Exclusions of NLSLs

Section 5(c)(7) of the NWPA

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

5(c)(7)(A) the cost of additional resources in an amount sufficient to serve any new large single load of the utility;

5(c)(7)(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

5(c)(7)(C) any costs of any generating facility which is terminated prior to initial commercial operation.

1981 ASCM Treatment of NLSLs

- Footnote 15(b) of the 1984 ASCM determined resource costs to serve NLSLs as follows:
  (1) Resources dedicated to NLSL;
  (2) Power purchases from BPA at the NR rate;
  (3) A pool of the utility's resources not committed to its load as of September 1, 1979; and
  (4) Most recently acquired baseload resource or LT power purchases.

1984 ASCM Treatment of NLSLs

- Endnote f/ of the 1984 ASCM determined resource costs to serve NLSLs as follows:
  (1) Resources dedicated to NLSL, and applicable Transmission;
  (2) Power purchases from BPA at the NR rate;
  (3) At average of all baseload resources not committed to its load as of September 1, 1979, and LT power purchases;
  (4) At the cost of the most recently completed or acquired baseload resource or LT power purchase;
  (5) If the NLSL is served on any energy or capacity interruptive basis, the Utility would provide BPA the fixed and variable costs of that service.

Summary of Proposed Changes to NLSLs

- Move Endnote d/ to the main body.
- Segregate Endnote d/ into two sections: (1) “Base Period NLSL”, and (2) “Exchange Period NLSL”.
- Draft new treatment for determining a Utility’s resource costs to serve its NLSL.
- Remove the NLSL exception.
- Remove the NLSL Formula Rate.

2008 ASCM Treatment of NLSLs

- Endnote d/ of the 2008 ASCM rolls over three sub-provisions to determine the resource costs of serving a Utility's NLSLs included in both the 1981 and 1984 ASCMs.
- Endnote d/ calculates NLSL resource costs as follows:
  1. For resources dedicated to serving a Utility's NLSL, the costs are those of the resource(s).
  2. For Utilities serving their load with NR power from BPA, apply BPA's NR rate.
  3. For all other, the costs are the weighted fully allocated costs of all the Utility's post-1979 resources and LT power purchases.

2008 ASCM – Endnote d/(3) Visual

- The Appendix 1 'NLSL Base New Calculation' tab performs Endnote d/(3).
- The averaged resource costs are then adjusted for Transmission.
- The fully allocated resource cost is multiplied by the NLSL MWh to derive the cost to remove from the Utility's ASC.

Year in Service			Kettle Falls	Colstrip 3 & 4	Boulder Park	Rathdrum	Spokane N.E.	Coyote Springs 2	
Fuel	Wind	Form 1 LF	Geo-Therm	Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas	
Energy (kWh)	0	19,124,000	308,291,000	1,641,846,000	63,905,000	779,307,000	112,000	2,265,353,000	5,077,938,000
Gross Plant in Service	$0		$145,991,402	$350,343,741	$34,233,031	$66,029,041	$14,481,395	$204,960,752	816,039,362
Accumulated Depreciation	$0							$ 69,678,243	$ 69,678,243
Net Plant In Service	$0	$0	$145,991,402	$350,343,741	$34,233,031	$66,029,041	$14,481,395	$274,638,995	885,717,605
Fuel Stock									0
Alloc. Plant Materials & Supplies	Maintenance and Supplies costs included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								12,772,256
Allocated General Plant - Net	General Plant costs included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								7,053,403
Total "Rate Base"	$0	$0	$145,991,402	$350,343,741	$34,233,031	$66,029,041	$14,481,395	$274,638,995	905,543,265
Weighted Cost of Capital	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%
Return on Capital	$0	$0	$12,131,886	$29,113,565	$2,844,765	$5,487,013	$1,203,404	$22,822,501	75,250,645
Annual Depreciation Expense									
Production Plant	$0								0
General Plant	General Plant Depreciation expense included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								400,164
Total Annual Depreciation Expense									400,164
Operations Expense Less Fuel	$0		$2,109,629	$9,409,687	$302,273	$279,621	$56,943	$2,132,077	14,290,230
Maintenance Expense	$0		$2,850,337	$7,679,310	$737,876	$325,657	$76,906	$2,285,568	13,955,654
Fuel			$11,997,451	$34,049,395	$1,982,207	$28,638,414	($4,255)	$46,437,759	123,100,971
Allocated A&G	A & G costs included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								17,472,569
Purchased Power Expense		$1,210,852							1,210,852
Federal Employment Taxes	Federal Employment Taxes included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								2,808,546
State Employment Taxes	State Employment Taxes included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								18,048
Property Taxes	Property Taxes included in NLSL Resource costs will be calculated using NLSL Functionalization Ratios.								6,091,799
Fully Allocated Cost ($)									254,599,479
Fully Allocated Cost ($/MWh)									$50.14
Average Cost of Post-1979 Base Period Resources									$50.14
ASC Transmission									$0.00
2023 cost of serving NLSLs under Endnote d									**$50.14**

2026 ASCM – Proposed NLSL Treatment

New provision to replace Endnote d/:

- …remove from the Utility's Base Period ASC the cost of additional resources sufficient to serve any New Large Single Load (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. Utilities with NLSLs that become operational as of the effective date of this 2026 ASCM, the resource costs will be based first on the average costs of post-2026 resources and LF power purchases, and then at the Utility's Base Period ASC for any remaining NLSL load.
  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.

2008 ASCM – Endnote d/ Escalation of NLSLs

- Endnote d/ provides escalation of Base Period NLSL load and costs to the Exchange Period as follows:
    1. Escalate fully allocated resource costs of NLSLs.
    2. Adjust for transmission.
    3. Add fully allocated costs of major resource adds/removals.
    4. The costs to serve NLSLs will change with resource adds/removals.
    5. The Exchange Period NLSL load will equal the Base Period NLSL load.

2026 ASCM – Proposed Escalation of NLSLs

- Bonneville will escalate the components of the resource costs used to serve NLSLs to the Exchange Period as follows:
  1. Escalate the components of the fully allocated resource costs to the Exchange Period.
  2. Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.
  3. The costs to serve NLSLs may change when the ASC changes due to resource additions/retirements.
  4. The Exchange Period NLSL load will equal the Base Period NLSL load.

Addressing the NLSL Exception

- The 2008 ASCM Final ROD at 89 recognized instances where a Utility's ASC could increase from the removal of an NLSL and associated resource costs. BPA was concerned such result went against the intent of the REP.
- The 2008 ASCM addressed this concern by disallowing a Utility's ASC to increase from the removal of NLSL load and associated resource costs.
- For the 2026 ASCM, BPA is proposing to eliminate this exception and remove NLSLs and associated resource costs from a Utility's ASC regardless of effect.

Addressing NLSL Formula Rate

- For the BP-14 ASC Review Process, BPA and Utilities adopted the NLSL Formula Rate to adjust utilities' ASC when an NLSL become operational during the Exchange Period.

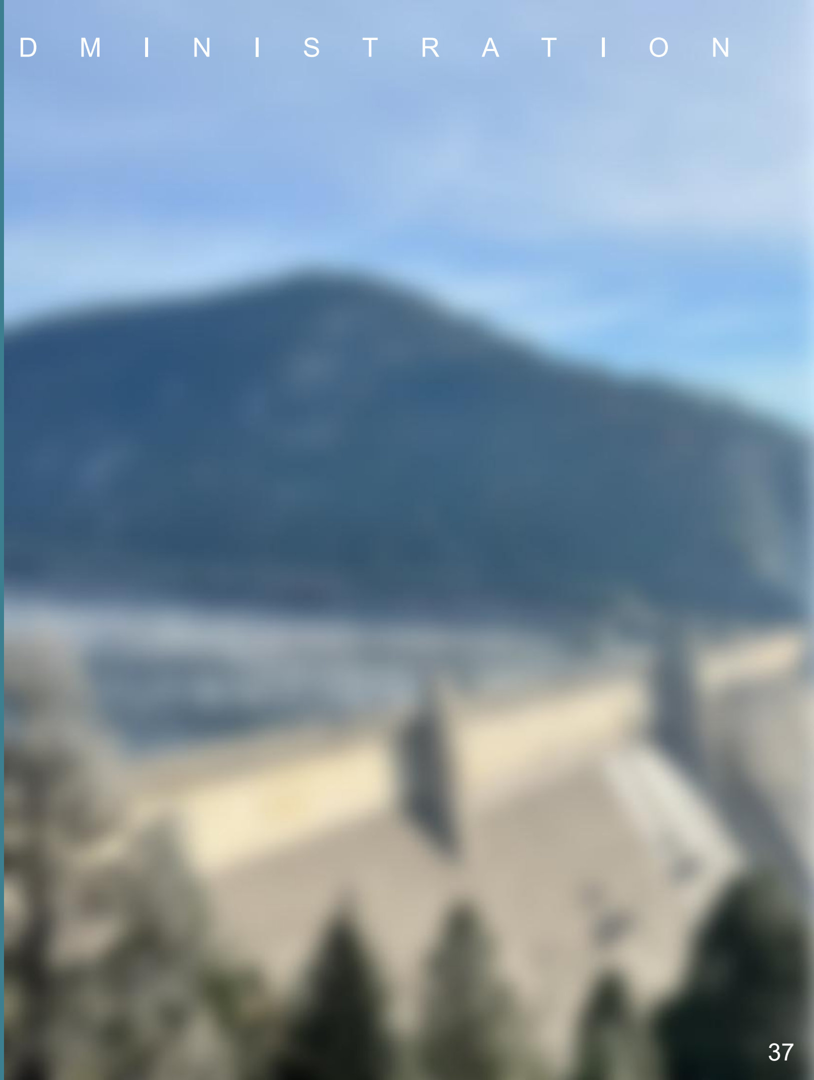
$$\text{ASC} = \frac{\text{Contract System Cost} - (\text{Cost of Serving New NLSL} * \text{Actual New NLSL MWh})}{\text{Contract System Load MWh} - \text{Actual New NLSL MWh}}$$

- For the 2026 ASCM, BPA is proposing to eliminate the NLSL Formula Rate and not adjust ASCs during an Exchange Period for NLSLs that become operational in this timeframe. New NLSLs will be picked up in subsequent ASCs.

Escalation Factors

Presenter – Michael Edwards

REP Technical Lead



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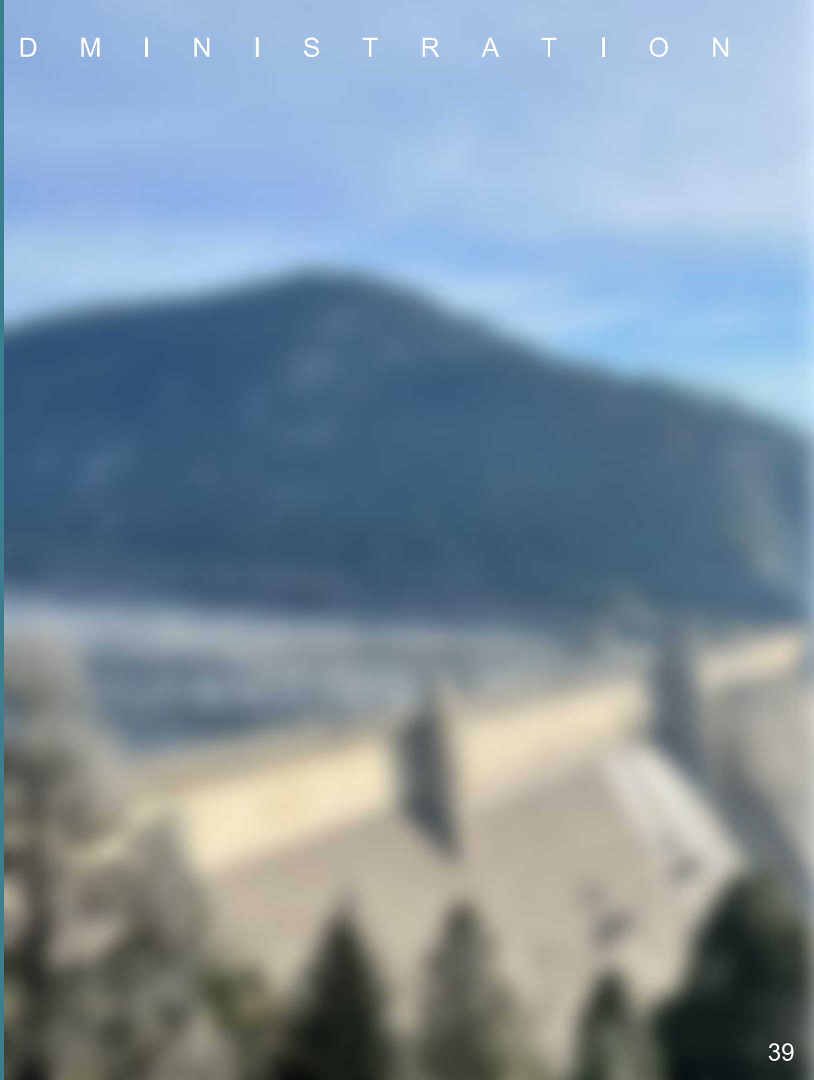
Escalation Provision Proposal

- The 2008 ASCM specifically names Global Insight as the source of escalation data.
- For the 2026 ASCM, BPA proposes to replace Global Insight with a general third-party reference.

Meeting Load Growth for ASC Determinations

Presenter – Michael Edwards

REP Technical Lead



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Proposed Purchase & Resale Weighting

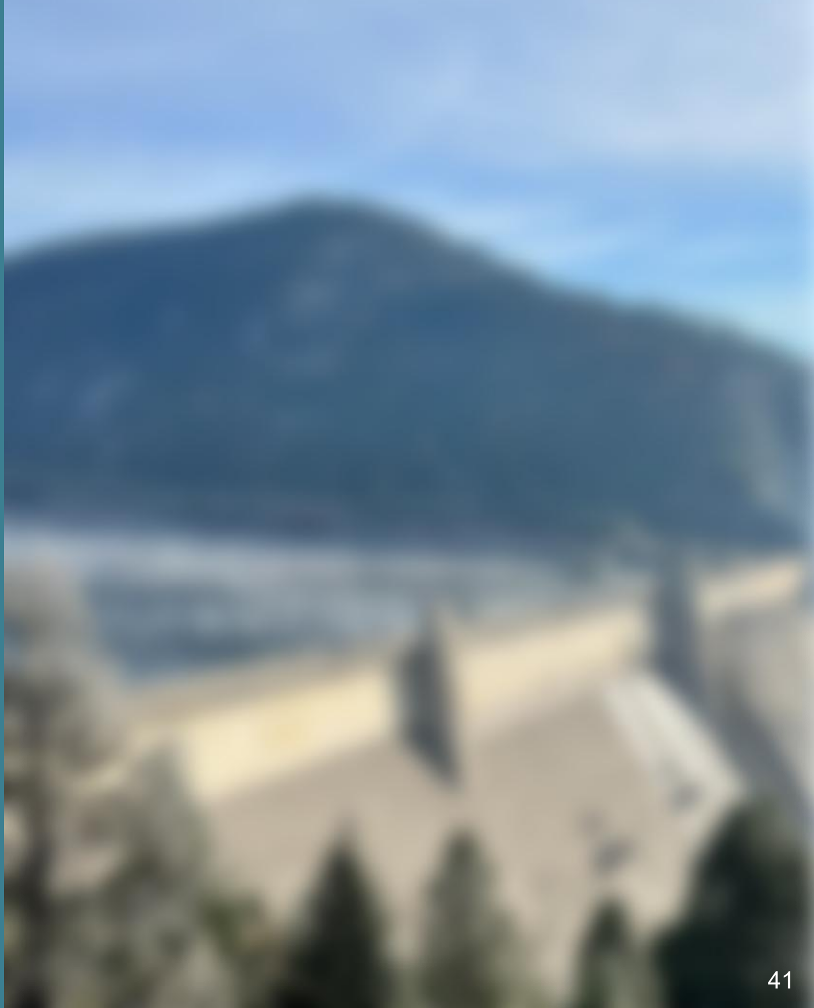
- Purchase & Sales for Resale data from Appendix 1
  - Currently, data from the base year and the previous two years are used to calculate the weighted average Purchase & Sales for Resale prices. The input is used in the ASC Forecast Model for modeling Purchases & Sales for Resale into the Exchange Period dependent on the load forecast and new resources.
  - Staff proposes using a 5-year weighted average instead of the current 3-year weighted average. Weighting over five years instead of three mitigates volatility by shifting the base year weight from 50% to 33%.

Example Years		5 yr. weighting		3 yr. weighting	
2026	Base	5	33%	3	50%
2025	Base-1	4	27%	2	33%
2024	Base-2	3	20%	1	17%
2023	Base-3	2	13%		
2022	Base-4	1	7%		

Summary of Proposed Changes to the ASCM

Presenter – Paulina Cornejo

REP Policy Lead



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Proposed to Carry Forward from 2008 ASCM

- Retain the FERC Form 1 (FF1) as the source data to populate the Appendix 1 and determine Utilities' ASCs.
- Set Base Period ASCs from historical FF1 data and escalate forward to establish Exchange Period ASCs.
- Maintain the Major Resource additions and removals provisions, and the Materiality thresholds.
- House the ASC Review Process procedural requirements in the Rules of Procedure and ASC Confidentiality Rules.
- Table 1: Functionalization and Escalation Codes remain unless otherwise proposed.

Proposed Structural Changes

- Segregate the ASCM into two main parts:
  - PART 1: ASC FERC Regs, Table 1, Endnotes and Appendix 1 Template
  - PART 2: BPA's ASC Rules of Procedure with embedded ASC Confidentiality Rules.
- Clarify the calculation of Base Period ASCs and Appendix 1 instructions.
- Move the Endnotes, as references, to Table 1 instead of the Appendix 1.
- Move the substantive text from the Endnotes into the body of the ASCM in Section 301.4 – Base Period ASC.

FERC Account Adds and Removals

- BPA is proposing to remove the following accounts as they are no longer listed on the FERC Form 1:
  - Account 108, Mining Plant Depreciation
  - Account 108, Leasehold Improvements
  - Account 906, Customer Service
  - Account 933, Transportation (Non-Major)
- BPA proposes adding the below Accounts to the Table 1, functionalized to Production:
  - Solar Production, 338.1 – 338.13
  - Wind Production, 338.20 – 338.34
  - Other Renewable Production, 339.1 – 339.13

Proposed Updates to 2008 ASCM Endnotes

- Endnote b/: Clarify the Federal Income Tax Rate in the "Rate of Return" tab to reflect the then in-effect rate.
- Endnote e/: Pare down the Distribution Loss Calculation to Method 3.
- Propose to average to the Mid-point Exchange Period by averaging forecasted start and end date of ASCs.
- Remove Above-RHWM and COU references.

Proposed Changes to Transmission, Acct 925 and ESP

- Transmission: Propose to disallow into ASCs all transmission costs, except for third-party transmission costs and transmission associated with sales for resale.
- Injuries and Damages: Propose to functionalize by the PTD ratio the portions of Account 925 approved for recovery by Utilities' state commissions.
- Energy Storage Plant: Propose to functionalize costs of energy storage plant using the PTD ratio.

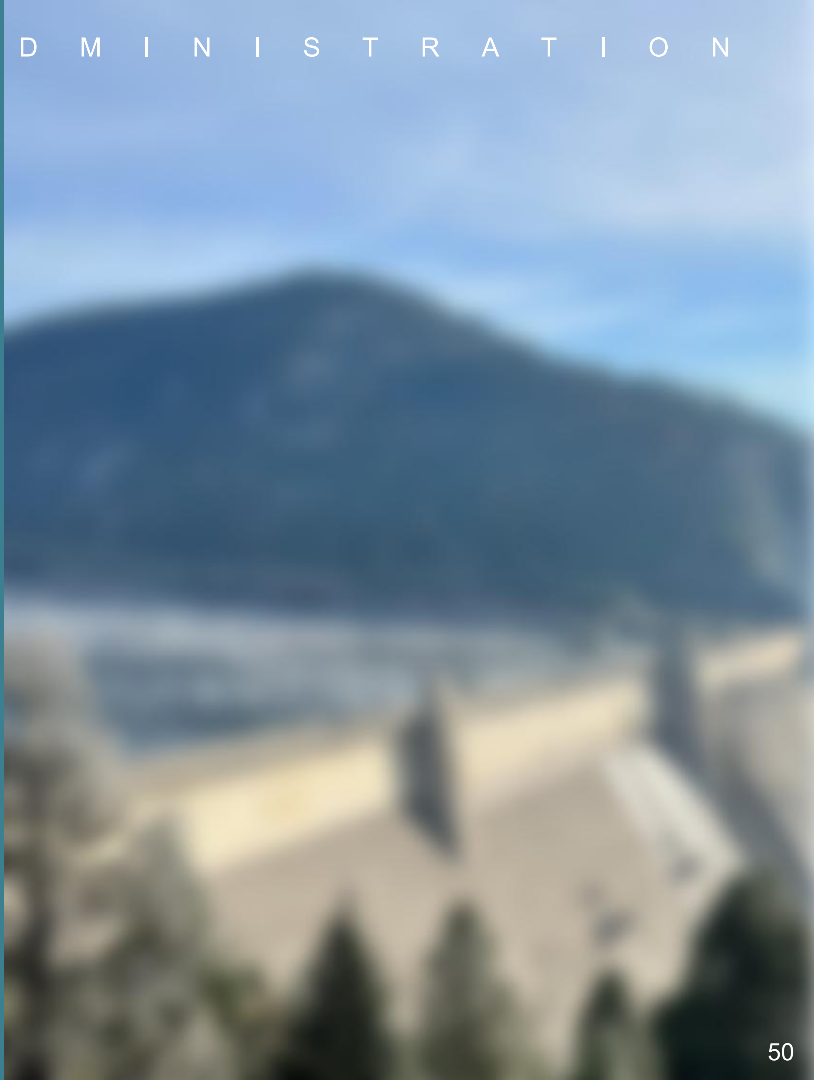
Proposed Treatment of NLSLs

- Segregate Endnote d/ into two sections: (1) “Base Period NLSL”, and (2) “Exchange Period NLSL”.
- Draft new treatment for determining a Utility’s resource costs to serve its NLSL.
- Remove the NLSL exception.
- Remove the NLSL Formula Rate.

Q&A

Next Steps: Preliminary Draft & WS 3

Workshop 1: Oct. 23rd	Workshop 2: Dec. 3rd	Preliminary ASCM Release: Dec. 10th	Workshop 3: Dec. 16th
• ASCM Structure • ASC Review Process and Rules of Procedures • Sections Carried Forward • Updates to FERC Accounts and ASCM Sections • Functional Overview of Appendix 1 and Forecast Model • WS 2 Topics	• Phase 2 Schedule Changes Proposed Changes: • Transmission Costs • Injuries and Damages (Account 925) • Energy Storage Plant • Treatment of NLSLs • Source of Escalation Data • Meeting Load Growth	• BPA releases Preliminary ASCM Draft for informal comment. • Regional parties submit informal comments to the REP2028@bpa.gov inbox.	• Questions on WS 1 and 2 Content • Walkthrough entire ASCM • Walkthrough Appendix 1 Template and Forecast Model • Customer-led Topics



Close-out

Presenter – Scott Winner

Power Planning and Forecasting Supervisor

POST 2028 REP

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

Attachment 4
BPA ASCM Presentation
December 16, 2025

Post-2028 Residential Exchange Program Average System Cost Methodology Workshop

Tuesday, December 16th, 2025

9:00 am – 4:00 pm

RHR and WebEx

POST 2028 REP

December 16th Workshop Agenda

Workshop Topics	Presenter(s)
Introductions, Agenda, and Schedule	Scott Winner
List of Changes to ASCM Part I and II	Paulina Cornejo
Walkthrough of Preliminary ASCM Redline	Paulina Cornejo and Richard Greene
List of Changes to Appendix 1	Michael Edwards
Walkthrough Appendix 1	Michael Edwards
Narrative of Forecast Model	Scott Winner
Forecast Model Procedure	Michael Edwards
Next Steps and Closeout	Scott Winner
Breaks	**Est. Times**
LUNCH	Noon – 1:00 pm

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

ASCM Workshop 3 Topics

Workshop 1: Oct. 23rd

- ASCM Structure
- ASC Review Process and Rules of Procedures
- Sections Carried Forward
- Updates to FERC Accounts and ASCM Sections
- Functional Overview of Appendix 1 and Forecast Model
- WS 2 Topics

Workshop 2: Dec. 3rd

- Phase 2 Schedule Changes

Proposed Changes:

- Transmission Costs
- Injuries and Damages (Account 925)
- Energy Storage Plant
- Treatment of NLSLs
- Source of Escalation Data
- Meeting Load Growth

Preliminary ASCM Release: Dec. 10th

- BPA releases Preliminary ASCM Draft for informal comment.
- Regional parties submit informal comments to the REP2028@bpa.gov inbox.

Workshop 3: Dec. 16th

- Questions on WS 1 and 2 Content
- Walkthrough entire ASCM
- Walkthrough Appendix 1 Template and Forecast Model

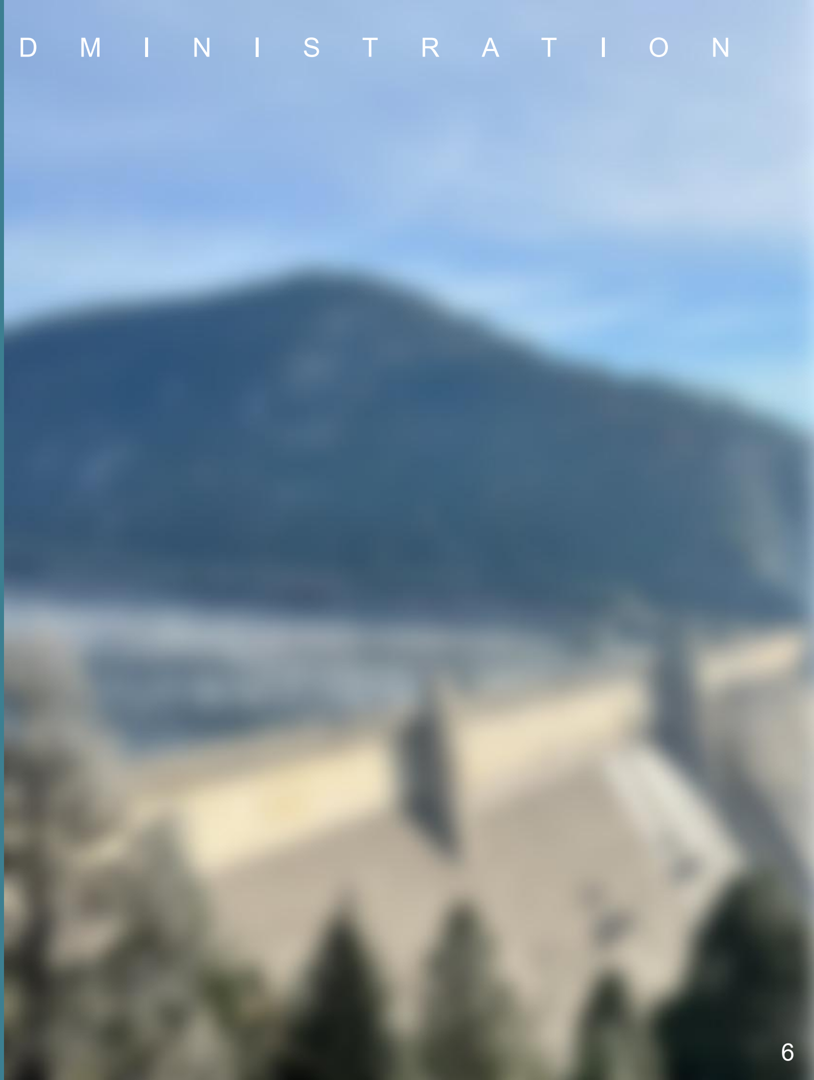
Phase 2 Schedule Update

Date	RPSA	ASCM
Nov 25, 2025, Tue	**Comments due**, Preliminary	
Dec 3, 2025, Wed		WS2
Dec 9, 2025, Tue	**Post**, Full	
Dec 10, 2025, Wed		**Post**, Preliminary
Dec 16, 2025, Tue		WS3
Jan 21, 2026, Wed	**Comments due**, Full	**Comments due**, Preliminary
Feb 3, 2026, Tue		**Post**, Full
Mar 6, 2026, Fri	ROD	
Mar 9, 2026, Mon		**Comments due**, Full
Apr 24, 2026, Fri		ROD
Late Jul 2026		FERC Interim Approval

BPA Staff Responses to Comments

Presenter – Paulina Cornejo

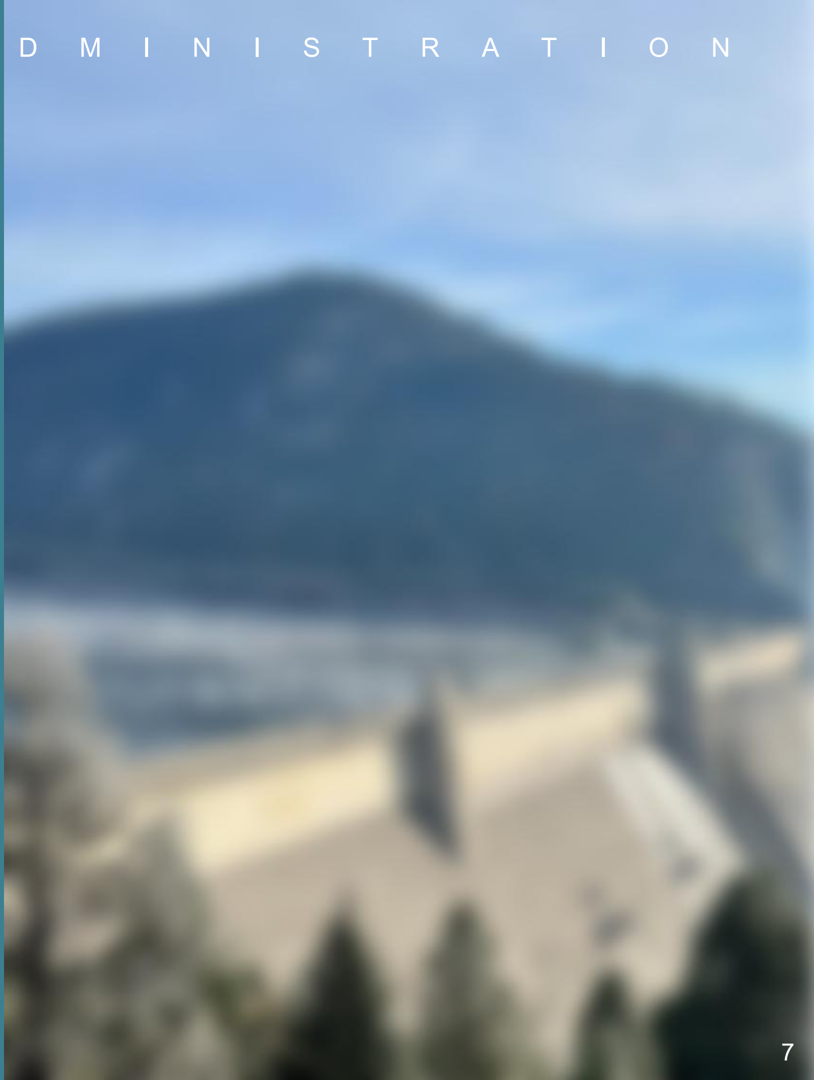
REP Policy Lead



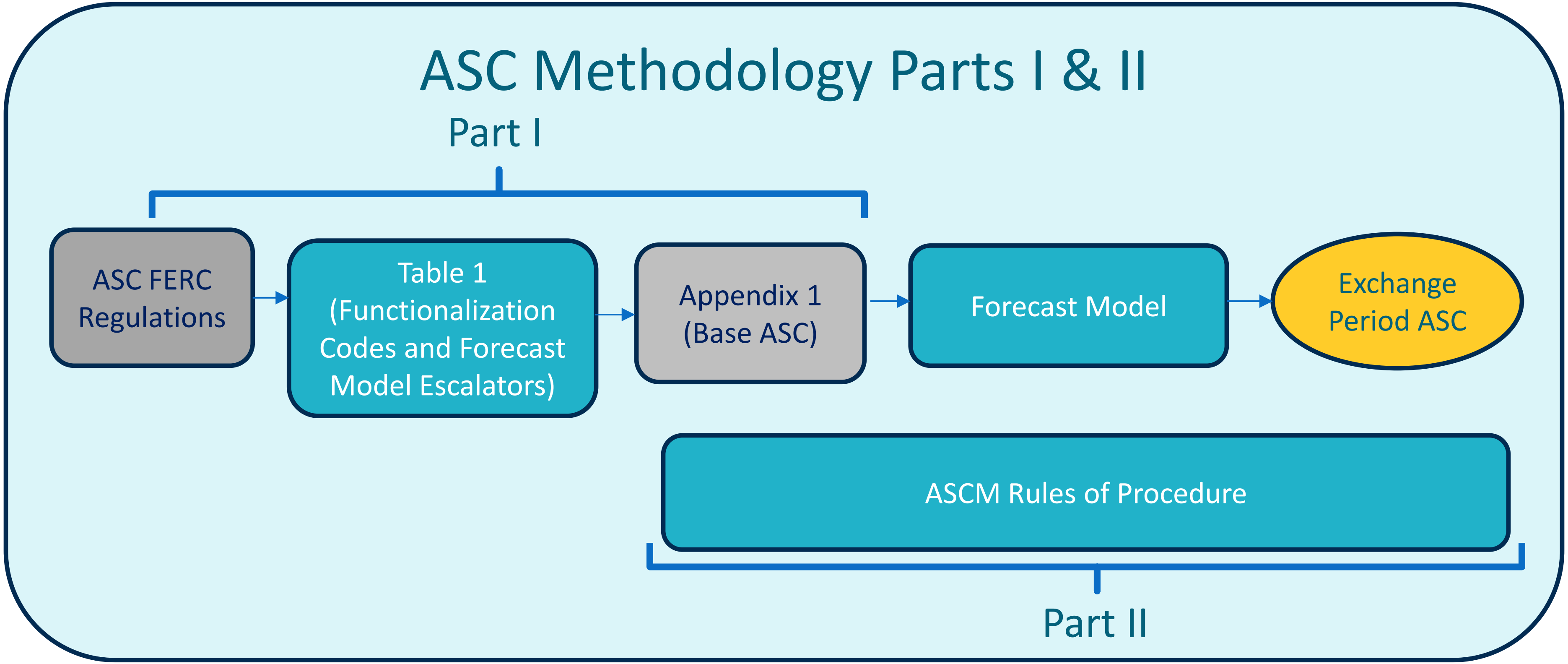
Summary of Changes to the ASCM

Presenter – Paulina Cornejo

REP Policy Lead



ASCM Roadmap



Proposed to Carry Forward from 2008 ASCM

- Retain financial data in the FERC Form 1 (FF1) as the source data to populate the Appendix 1 and determine Utilities' ASCs.
- Set Base Period ASCs from historical FF1 data and escalate forward to establish Exchange Period ASCs.
- Maintain the Major Resource additions and removals provisions, and the Materiality thresholds.
- House the ASC Review Process procedural requirements in the Rules of Procedure and ASC Confidentiality Rules.
- Table 1: Functionalization and Escalation Codes remain unless otherwise proposed.

Proposed Structural Changes from 2008 ASCM

- Segregate the ASCM into two main parts:
  - PART 1: ASC FERC Regs, Table 1, and Appendix 1 Template
  - PART 2: BPA's ASC Rules of Procedure with embedded ASC Confidentiality Rules
- Move substantive text from the Endnotes into the body of the ASCM in Section 301.4 – Base Period ASC.
- Have Endnotes as references to Table 1 instead of the Appendix 1.

List of Proposed Changes to Part I

- **Added a document index**
- **Changes to section 301.2, Definitions**
  - Revised Average System Cost Review Process
  - Deleted Contract High Water Mark
  - Added Confidential Information
  - Deleted Consumer Owned Utility
  - Revised Contract System Costs
  - Revised Contract System Load
  - Added text to Direct Analysis
  - Deleted Global Insight
  - Added Mid-Rate Period Adjustment
  - Deleted Net Requirements
  - Deleted Priority Firm Power
  - Added PF Exchange Rate
  - Added Rate of Return
  - Revised Review Period
  - Deleted COU references:
    - text on COUs in Labor Ratios
    - Rate Period High Water Mark (RHWM)
    - RHWM Process
    - RHWM Exchange Load
    - RHWM System Resources
    - Tier 1Priced Power
    - Tier 1 System Resources
    - Tiered Rates Methodology

List of Proposed Changes to Part I Cont.

- **Changes to section 301.3, Filing Procedures**
  - Added reference to the ASC Rules of Procedure
- **Changes to section 301.4, Base Period ASC**
  - Revised (a) with introductory sentence
  - Revised (c) to point to directly to the Senior Financial Officer Attestation
  - Added to (d) reference to Base Period ASC
  - Updated hyperlink in (e)
  - Added (e)(8) about other supplemental tabs
  - Added to (f)(1) reference to Table 1
  - Expanded (g) to include associated and/or subsidiary companies
  - Deleted (j) because Senior Financial Officer Attestation included in Part II
  - Added new (j) statement on demand-side management and demand response

List of Proposed Changes to Part I Cont.

- **Changes to section 301.4: Base Period ASC con't**
  - Added language to (m)(2) regarding combining functionalizations
  - Cleaned up (n) on calculating Distribution Losses and added to (n)(2)
  - Clarified (o) on timing of Rate of Return
  - Clarified (o)(1)-(3) on timing of federal corporate income tax rate
  - Substantive edits to (p) on NLSLs, which were discussed in detail in Workshop 2
  - Deleted (v) on treatment of transmission under FERC Order 888
  - Added (v) on treatment of Energy Storage Plant
  - Added (w) on Injuries and Damages
  - Added (x) on treatment of Transmission costs
  - **Added (y) on Demand-side management and demand response**

List of Proposed Changes to Part I Cont.

- **Changes to section 301.5, Exchange Period ASC Determination**
  - Revised (a) with introductory sentence
  - Revised language in (a)(2) on escalating to midpoint of Exchange Period
  - Replaced in (a)(4) Global Insight with third party
  - Changed in (b)(2)(ii)(A)-(D) determination of average ST purchased power prices and sales for resale prices from three years to five years
  - Added to (c)(1) reference Residential Purchase and Sale Agreement
  - Deleted from (c)(3) transmission investments and long-term transmission contracts
  - Deleted (c)(6) on transmission wheeling revenues calculation
  - Transferred from 301.4(p) the escalation provisions for NLSLs to 301.5(c)(10)
  - Simplified (c)(13) to directly reference the ASC Confidentiality Rules
  - Deleted (g) on provisions for Consumer-owned Utilities

List of Proposed Changes to Part I Cont.

- **Changes to section 301.6, Changes in ASCM**
  - Removed text in (a)
- **Changes to section 301.7, Provisions for Public Customers**
  - Added provision in the instance a Public customer participates in the REP
- **Changes to section 301.8, Appendix 1 Instructions**
  - Deleted the entire section as the operative provisions are now housed in 301.4

Table 1 Changes

- **List of revisions to Table 1**
  - Added Solar Production, 338.1 – 338.13
  - Added Wind Production, 338.20 – 338.34
  - Added Other Renewable Production, 339.1 – 339.13
  - Added Energy Storage Plant, 387-387.12
  - Added Computer Hardware, 397.1
  - Added Computer Software, 397.2
  - Changed Communication Equipment account number from 397 to 397.3
  - Deleted Mining Plant Depreciation, Account 108
  - Deleted Leasehold Improvements, Account 108

Table 1 Changes Cont.

- Deleted line-item Depreciation and Amortization Reserve (Other)
- Added Investment in Subsidiary Companies, 123.1
- Removed "EPA" from Account names, 158.1 and 158.2
- Deleted Preliminary Natural Gas Survey and Investigation Charges, 183.1
- Deleted Other Preliminary Natural Gas Survey and Investigation Charges, 183.2
- Added line for Schedule 2: Capital Structure and Rate of Return
- Added Power Purchased for Storage Operations, 555.1
- Deleted line-item BPA REP Reversal

Table 1 Changes Cont.

- Deleted Customer Service and Information, 906
- Added Supervision, 907
- Added line-item Commission Approved Injuries and Damages
- Deleted Transportation Expenses (Non-Major), 933
- Added line-item Transmission for Sales for Resale

- **Changes to Table 1 Endnotes**
  - Moved Endnotes references from Appendix 1 to Table 1

List of Proposed Changes to Part II

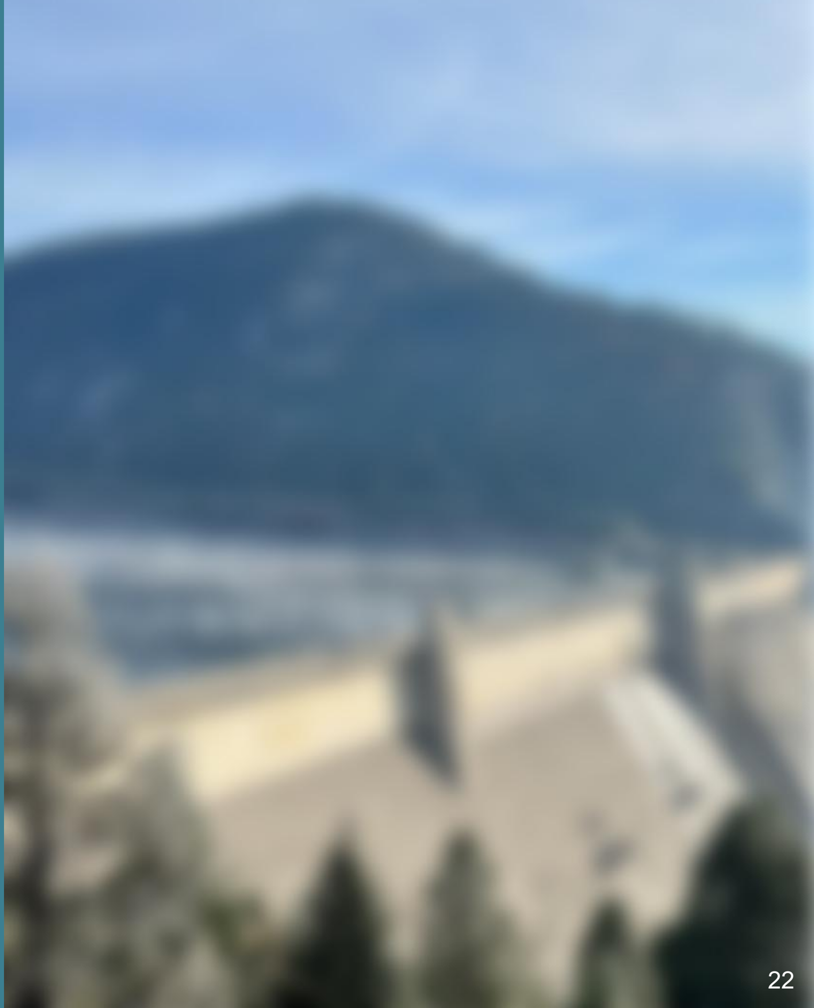
- **Added an Index page**
- **Deleted a paragraph from the Summary, section 1**
- **Changes to section 2, Filing Procedures:**
  - Added a descriptive paragraph to 2.1
  - Clarified in 2.1.1 the Base Period ASC Filings
  - Modified in 2.1.1.1 the requirements of the Utility's filing package
  - Revised in 2.1.2 provisions on Informational ASC Filings
  - Removed text from each subsection in 2.2
  - Removed text in 2.3 on Utilities without an executed RPSA

List of Proposed Changes to Part II Cont.

- **Changes to section 3, ASC Review Process**
  - Added clarifying text to 3.1.1 - 3.1.3
  - Revised 3.1.4 and 3.1.5 regarding intervention petitions
  - Added text to 3.3.1 on the discovery process
  - Added clarifying text to 3.4 and 3.5.1
  - Deleted a paragraph following 3.7.2
- **Changes to section 4, ASC Review Process Schedule**
  - Updated the link in 4.2
- **Changes to section 5, Access to Filing Utility's Data in Retail Rate Proceedings**
  - Added clarifying text in 5.1 - 5.2 regarding BPA's access to Utility's data in retail rate proceedings

List of Proposed Changes to Part II Cont.

- **Attachment A, Senior Financial Officer Attestation**
  - Added the term “Base Period”
  - Deleted references to COUs
- **Attachment B, 2026 ASC Confidentiality Rules**
  - Transferred terms “ASC Filing” and “Confidential Information” to Part I, Regulations
  - Deleted “Utility” definition
  - Replaced term “Consent to be Bound” with “ Confidentiality Agreement” throughout
- **Attachment B-1, Confidentiality Agreement**
  - Replaced term “Consent to be Bound” with “ Confidentiality Agreement” throughout



Walkthrough ASCM Redline

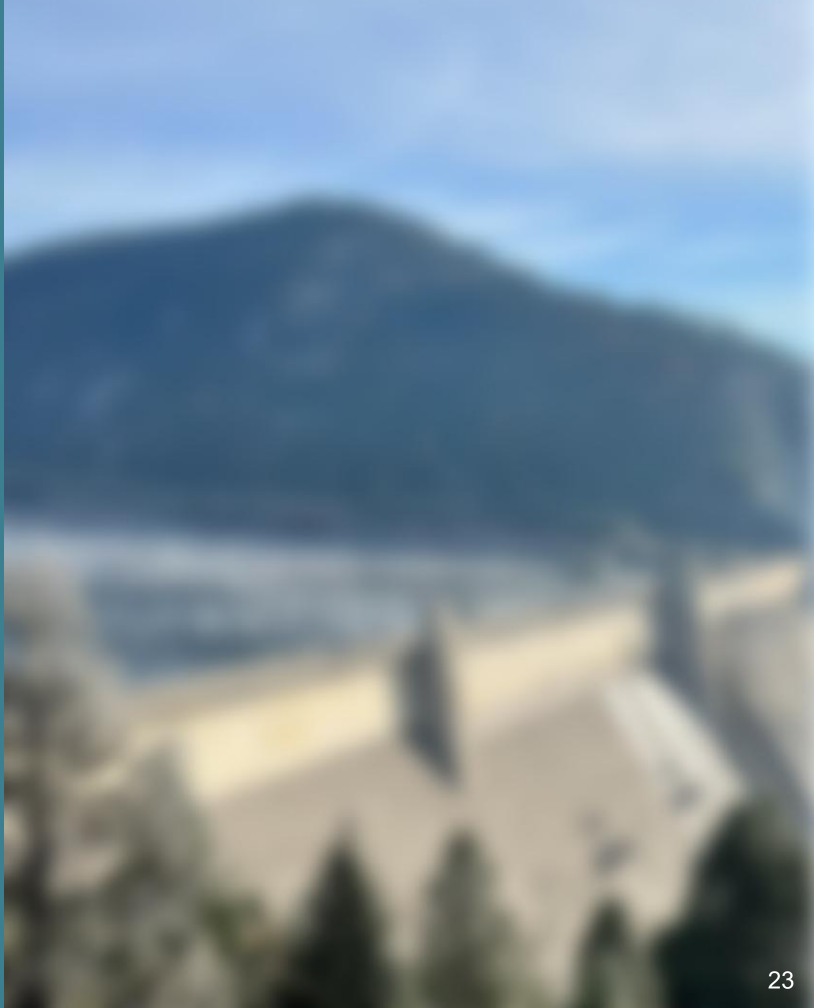
Presenter – Richard Greene

Senior Attorney-Advisor

Changes to and Walkthrough of Appendix 1

Presenter – Michael Edwards

REP Technical Lead



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List of Proposed Changes to Appendix 1 Cont.

- **Proposed changes to Schedule 1 tab**
  - Changes to Accounts and/or line-items reflected in Table 1
- **Proposed changes to Schedule 1A tab**
  - No edits
- **Proposed changes to Schedule 2 tab**
  - No edits
- **Proposed changes to Schedule 3 tab**
  - Changes to Accounts and/or line-items reflected in Table 1
    - Includes addition of line-item for Commission Approved Injuries and Damages
- **Proposed changes to Schedule 3A tab**
  - No edits

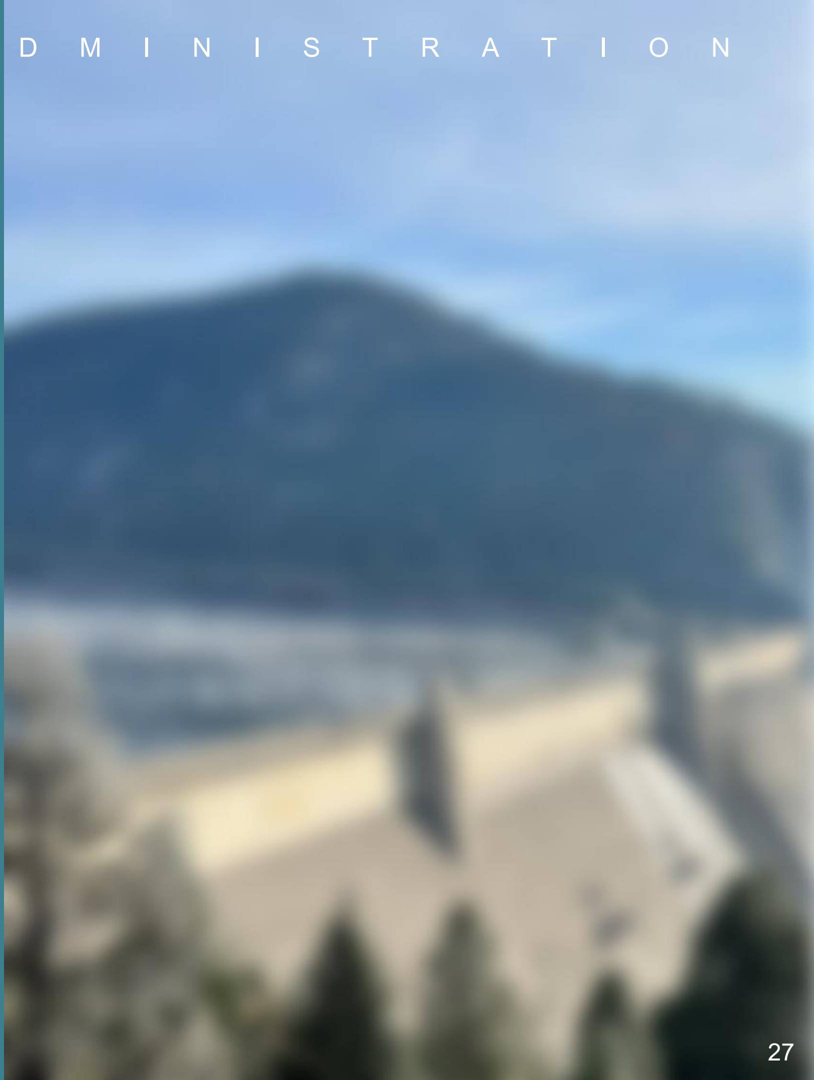
List of Proposed Changes to Appendix 1 Cont.

- **Proposed changes to Schedule 3B tab**
  - Changes to Accounts and/or line-items reflected in Table 1
- **Proposed changes to Schedule 4 tab**
  - Removed Transmission from ASC calculation
  - Removed RHWM references
- **Proposed changes to 3YR PP & OSS tab**
  - Added two years of data and reweighted the price spread
- **Proposed changes to Load Forecast tab**
  - No edits
- **Proposed changes to Distribution Loss Calc tab**
  - No edits

List of Proposed Changes to Appendix 1 Cont.

- **Proposed changes to Salaries tab**
  - No edits
- **Proposed changes to Ratios tab**
  - No edits
- **Proposed changes to New Resources- Individual, New Resources- Group, Materiality – Individual, Materiality – Group, Wind Resources Costs tabs**
  - No edits
- **Proposed changes to NLSL Base New Calc tab**
  - Added new line-items
  - Removed the ASC Transmission line-item
- **Deleted A-RHWM Ratios, Above-RHWM Base Calc, Tiered Rates tabs**

Narrative and Running of Forecast Model



Presenters – Scott Winner

Power Planning and Forecasting Supervisor

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A Guide to the Exchange Period ASC

- **What We Analyze:** The ASC Forecast Model uses a Utility's financial and operational data to calculate the Utility's ASC for the Exchange Period.

- **The Model's Approach:** The calculation is performed in a single, integrated process within Excel, where all the complex math occurs simultaneously to produce final ASCs.

- **Why It's Important:** Calculating Exchange Period ASCs is a crucial step in BPA's rate-setting process to determine Exchange Period benefits.

- This section goes through the fundamental steps involved in determining the Utility's Exchange Period ASC, clarifying how all these elements come together in our existing model.

Where the Data Comes From

- Utility's Appendix 1
  - Schedules (Rate Base, ROR, O&M, A&G, wages, revenues, Market purchases & Sales)
  - Load Forecast (Distribution losses)
  - New Resources
  - NLSL(s)
- Third Party Data for Escalation
  - Escalations for specific codes in Table 1
- BPA
  - Energy Price Forecasts
  - Interest rate

Completing the Appendix 1 Schedules

- **Initial Cost Data:** The Utility populates the Schedules from its FERC Form 1.
- **Functionalized PROD, TRANS and DIST/Other:**
  - These rows with will be populated first from TOTAL.
- **Functionalized Direct:**
  - The Utility manually assigns costs from TOTAL.
- **Ratio calculations**
  - This is done is a specific order, because the resulting PROD, TRANS, and DIST population can feed the next ratio calculation. The order is:
    - **PT (Production & Transmission) Costs**
    - **LABOR Costs**
    - **TD (Transmission & Distribution) Costs**
    - **Remaining General Costs:** General Plant (GP), General Plant Maintenance (GPM), and Production, Transmission, Distribution & General (PTDG).

Costs to Exchange Period ASC

- The Rate of Return from Schedule 2 is applied to Schedule 1
- Total costs come from Schedules 2, 3, 3A, and 3B
  - Both the Appendix 1 and the Forecast Model keep track of the credits and debits to calculate the total exchangeable costs.
- Base Period ASC
  - Base Contract System Cost/Contract System Load
- Exchange Period ASC
  - Escalated Exchange Period Contract System Costs/Forecasted Exchange Period Contract System Load
    - Updated with new resources and adjusted to exclude NLSLs

Projecting Costs into the Future

Once initial costs are set, the model iterates monthly to the end of the Exchange Period

- Escalators get applied to many Total and Direct Analysis PROD, TRANS, DIST accounts
- Repeat Base Period operations for populating PROD, TRANS, DIST in the schedules
  - Functionalized PROD, TRANS, DIST
  - Recalculate ratios and populate PROD, TRANS, DIST

Short-Term Sales for Resale and Purchases

- Applies to accounts 555 and 447.
- Special operations apply to these accounts in the model to solve for load/resource balance. It is assumed increases in load will be met with short-term Purchases and decreases with short-term Sales.
- The Appendix 1 provides the Utility's Base Period price spread for Purchases and Sales.
- BPA's Energy Price Forecasts are used for estimating future costs, and the price spread estimates the Utility's Purchase and Sales prices.
- The Purchase and Sales costs will be applied to the changes in the load forecasts with Purchases increasing and Sales decreasing costs

Integrating New Resources in the Model

- Costs of new resources are reflected in the Utility's ASC at the time they come online.
- New resources are assumed to be available to serve load growth.
  - New resource energy (MWh) is netted against changes in Load during the Short-Term Sales for Resale and Purchases calculation to achieve load/resource balance.
  - New Resource, long-term contracts, are added to long & intermediate term purchase costs and removed from the Sales and Purchases calculation.

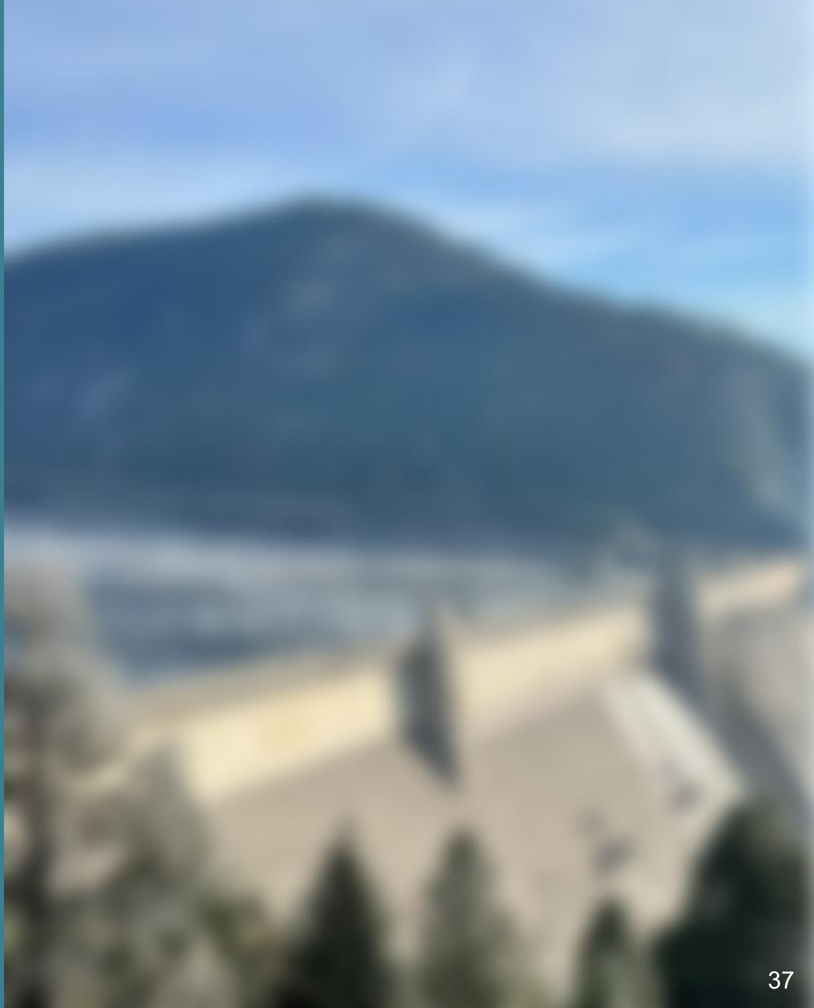
New Large Single Loads

- The NLSL load and associated resource costs are incorporated into the model's monthly iteration cycles at their expected dates.
- The Base Period NLSL inputs are escalated in accordance with the provisions in the ASCM.

Exchange Period ASC

- Numerator – Contract System Costs
  - Annualized average of the costs from the first and last monthly calculation of ASC in the model.
    - Except for Accounts 555 and 457, Short-Term Sales for Resale and Purchases, which are values from the midpoint of the Exchange Period
- Denominator – Contract System Load
  - Average of first and last year forecasted loads.

Forecast Model Procedure



Presenters – Michael Edwards

REP Technical Lead

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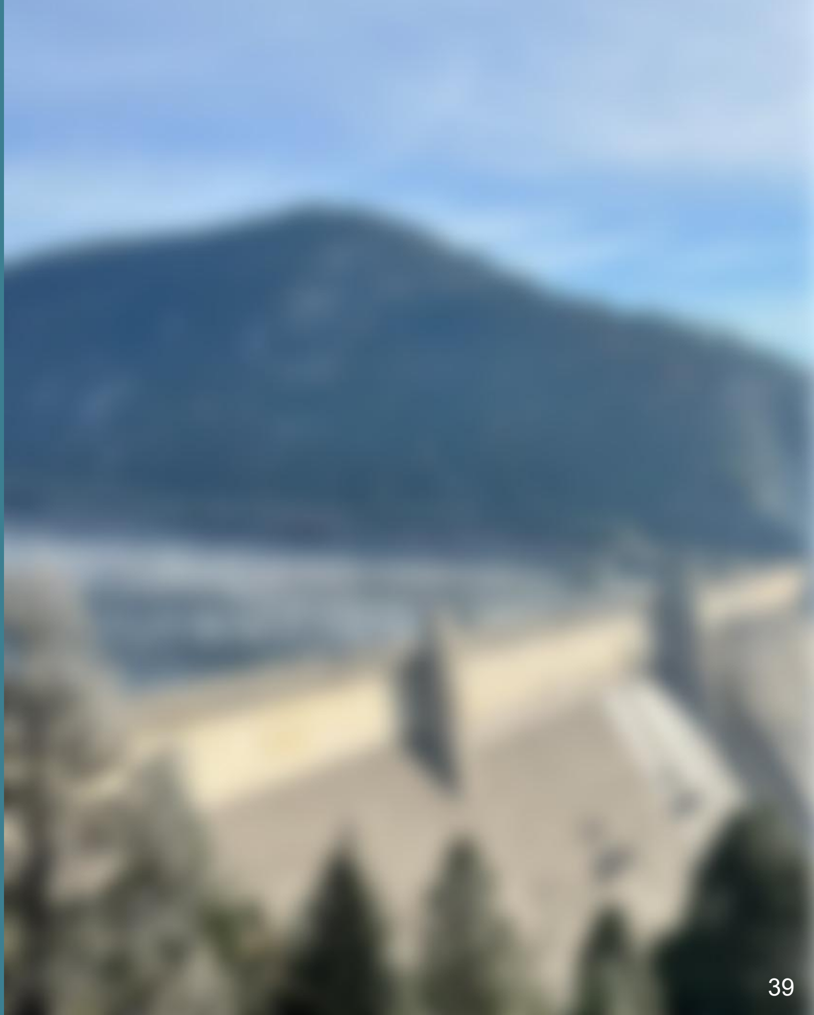
Q&A

Closeout

Presenter – Scott Winner

Power Planning and Forecasting Supervisor



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Phase 2 Schedule Update

Date	RPSA	ASCM
Nov 25, 2025, Tue	**Comments due**, Preliminary	
Dec 3, 2025, Wed		WS2
Dec 9, 2025, Tue	**Post**, Full	
Dec 10, 2025, Wed		**Post**, Preliminary
Dec 16, 2025, Tue		WS3
Jan 21, 2026, Wed	**Comments due**, Full	**Comments due**, Preliminary
Feb 3, 2026, Tue		**Post**, Full
Mar 6, 2026, Fri	ROD	
Mar 9, 2026, Mon		**Comments due**, Full
Apr 24, 2026, Fri		ROD
Late Jul 2026		FERC Interim Approval

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