Bonneville Power Administration

Draft 2026 ASCM Methodology

September 11, 2026

Draft of BPA's
2026 Average System Cost Methodology

<u>Part I: FERC Regulation</u>

<u>Part II: BPA's Rules of Procedure for ASCs</u>

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.

Commission. Federal Energy Regulatory Commission.

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).

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, including its inputs, 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.

Public Power Entity. A public body or cooperative that is entitled to preference and priority under the Bonneville Project Act of 1937 and that has executed a Residential Purchase and Sale Agreement.

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.

(c) Filing of Appendix 1 for Utilities with changes in service territory. Utilities will file multiple, contingent, Base Period ASC filings to reflect changes to service territories as required by Section 301.5(f).

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.

(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 sufficient documentation, as determined by BPA, will result in the entire Account being functionalized using the default functionalization, or if no default exists, to Distribution/Other for all schedules with the exception of items included in Schedule 3B, Other Included Items, where certain Accounts must be functionalized to Production as appropriate.

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

(1) Method 1, Distribution Loss Study:

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

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

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

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

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

(o) The overall Rate of Return (ROR) to be applied to a Utility's Exchange Period rate base as shown in Appendix 1 must be equal to its weighted cost of capital (WCC), including debt, preferred stock, and equity (as adjusted below), from its most recently approved Regulatory Body rate order in effect at the time the Utility submits its ASC Filing. The return on equity will be weighted so as to remove the return on equity associated with transmission pursuant to the formula described in (1) below. The return on equity associated with transmission shall be equal to the return on equity determined in FERC-approved transmission rates, including any ROE adders (FERC Tran ROE). 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) from a Utility's most recently-approved Regulatory Body rate order (State ROE) will be weighted to remove the FERC Tran ROE pursuant to the following formula:

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

where the Tran Rate Base % and Non Tran Rate Base % are as calculated in Schedule 2 of the Appendix 1.

(2) The non-transmission ROE 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:

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 for NLSLs without contractually dedicated resources procured by the Utility to serve that NLSL will be based first on the weighted average costs of all non-dedicated post-2026 resources and long-term (LF) power purchases(five-year duration or longer), and then at the Utility's Base Period ASC for any remaining NLSL load.

(i) For purposes of determining the average costs of the Utility's post-2026 resources, Bonneville will include an individual resource's fixed and annual costs, and a portion of general plant, A&G, other expenses and revenues, and LF power purchases. The resource costs will exclude (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to Section 5(c) of the Northwest Power Act; and (c) resources sold to Bonneville, pursuant to Section 6(c)(1) of the Northwest Power Act.

(2) For a Utility with NLSLs that become operational after the effective date of this 2026 ASCM, the resource costs for NLSLs with contractually dedicated resources procured by the Utility to serve that NLSL load will be based first on the actual costs of those post-2026 resources and LF power purchases (five-year duration or longer). Any remaining NLSL load after the contractually dedicated resources will be determined in accordance with section 301.4(p)(1)

(3) 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.

(4) 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 costs: Bonneville will allow DIRECT functionalization of Energy Storage Plant or PTD as default ratio. Energy Storage Expenses: Operation, and Energy Storage Expenses: Maintenance costs will apply the same functionalization as Energy Storage Plant.

(w) Injuries and Damages. FERC Account 925 will initially be functionalized by the LABOR ratio. If the FERC Account 925 costs functionalized to PROD do not exceed 5% of the Utility's modified net income as described below, this amount is included in the Utility's ASC.

(1) Calculation of 5% Modified Net Income Threshold. A Utility's modified net income shall be calculated as net income before extraordinary items (FERC Form 1 page 114-117, line 71) plus total Account 925 costs (FERC Form 1 page 320-323, line 186). The threshold for requiring additional documentation as required by Section (w)(3) below is 5% of a Utility's modified net income. If modified net income is negative, the threshold is $0.

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

(2) Determining whether the threshold has been exceeded. To determine whether the threshold has been exceeded, the amount of FERC Account 925 costs functionalized to PROD (Appendix 1, Schedule 3) divided by the modified net income calculated in Section (w)(1) above. If this amount is less than or equal to 5%, then the Account 925 costs functionalized to PROD will be included in a Utility's ASC. Amounts above the 5% threshold may be included in ASC if a Utility provides applicable documentation as described in Section (w)(3) below.

(3) State-approved Injuries and Damages.

(i) The Utility must submit with its ASC filing all work papers, documents, and other materials to justify costs in the *Commission Approved Injuries & Damages* line item by demonstrating

(A) approval of Injuries and Damages for retail rate recovery in the Base Period by state commission orders, and

(B) that such costs have not been recovered through other accounts. The ASCM will not allow double recovery of these costs recovered through other accounts (e.g. Account 925, or Regulatory Assets or Liabilities).

(ii) For costs that meet the requirements of (w)(3)(i) above, the Utility must perform a Direct Analysis or receive the default functionalization of the LABOR ratio.

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

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

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

(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.

(z) Regulatory assets and liabilities. To include regulatory costs or liabilities in a Utility's ASC, a Utility must perform a Direct Analysis. For example, accounts where regulatory assets or liabilities may occur include: Other Regulatory Assets, Account 182.3; Miscellaneous Deferred Credits, Account 186; Other Deferred Credits, Account 253; Other Regulatory Liabilities, Account 254; Regulatory Debits, Account 407.3; Regulatory Credits, Account 407.4. The Utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). Regulatory assets or liabilities will not be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.

§ 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.

[NOTE: Paragraph 2 immediately below is the status quo from the 2008 ASCM, included in every previous draft of the 2026 ASCM. This was presented as "Option 1" at the July 31, 2026 ASCM workshop.]

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

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

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

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

(1) Three (3) times Base Period spread.

(2) Two (2) times (Base Period minus 1) spread.

(3) One (1) time (Base Period minus 2) 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.

[NOTE: Paragraph 2b immediately below is the staff alternative presented as "Option 2" at the July 31, 2026 ASCM workshop. Under this option, the following would be added to the Definitions section:

Rate Case Firm Forecast. The "Remarketing Value" as determined in BPA's Power Rates Study.

Rate Case Spot Forecast. The "market price" as determined in BPA's Power Rates Study.]

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

(i) The Base Period short-term purchase and sales for resale expense will be held constant through the Exchange Period. Any change in the load forecast after the Base Period will be served by additional resources and/or additional short-term purchases and sales for resale as follows:

(A) The first step will net any new resources or retirements against total change in load, and will use a Utility-provided forecast to value additional purchased power expenses and sales for resale revenue to be included in the Exchange Period ASC. Any remaining surplus or deficit will be served by short-term power purchases and sales for resale.

(B) The second step will use short-term firm and spot market price forecasts, or their successors, from the Rate Case concurrent with the Exchange Period. Short-term purchases will use the Rate Case Firm Forecast, and short-term sales for resale will use the Rate Case Spot Forecast to calculate Exchange Period ASCs.

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

(1) Unless otherwise limited under the Residential Purchase and Sale Agreement between Bonneville and the Utility, during the Exchange Period, Bonneville will allow changes to a Utility's ASC to account for major resource additions or reductions that are used to meet a Utility's retail

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

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

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

(i) Production or generating resource investments;

(ii) Long-term generating contracts;

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

(iv) Hydroelectric relicensing costs and fees; and

(v) Plant rehabilitation investments.

(4) Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's Exchange Period ASC provided that the major resource addition or reduction meets the following materiality threshold. A resource that becomes operational after the Base Period, but prior to the publication of the Final ASC Report, must result in a percentage change of 0.5 percent or greater in the utility's Base Period ASC to be considered material. During the Exchange Period, the resource addition or reduction must result in a 2.5 percent or greater change in a Utility's Base Period ASC to be considered material. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.

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

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

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

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

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

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

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

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

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

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

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

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

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

(d) Forecasted Contract System Load and Exchange Load. All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss analysis as described in Endnote j 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. If a participating Utility forecasts that it will acquire additional 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, an Appendix 1 that does not reflect the acquisition or loss of service territory; and

(2) Second, an Appendix 1 that incorporates the following changes:

(i) Contract System Load that reflects the change in service territory, and are in accordance with (d) above.

(ii) Exchange Load that reflects the change in service territory, and are in accordance with (d) above.

(iii) New resource additions and retirements associated with the change in service territory.

(3) The Utility's ASC will be updated concurrent with the effective date of the change in service territory.

(g) This subsection applies to changes to a Utility's service territory occurring after filing of the Appendix 1 and before the end of the Exchange Period, or for any Utility that does not have a full-year FERC Form 1 for the Base Period. If a Utility acquires or loses 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

Exchange Load, then the established ASC will remain assigned to the territory in question. The ASC established as part of the ASC Review Process will not be altered, and the Exchange Loads of both Utilities will be adjusted to reflect the change in service territory between Utilities. If a Utility assumes the service territory, in whole or in part, of another Utility, then the acquiring Utility will assume the current ASC of the prior Utility for the transferred service territory for the duration of the Exchange Period, or until the Utility has a full-year FERC Form 1 for the Base Period. BPA may calculate a weighted average of the two ASCs for billing purposes.

(i) If a newly-formed Utility assumes the service territory, in whole or in part, of an existing Utility, then the new Utility will assume the current ASC of the prior Utility until the newly-formed Utility has a full-year FERC Form 1 for the Base Period.

(ii) If a newly-formed Utility assumes the service territory of two or more Utilities, then the new Utility's ASC shall be the weighted average of the prior Utilities' current ASCs, weighted by the percentage of each service territory assumed from the respective Utilities, until the newly-formed Utility has a full-year FERC Form 1 for the Base Period.

(iii) If a newly-formed Utility is formed from the service territory, in whole or in part, of a Public Power Entity, or other utility, that does not have a Residential Purchase and Sale Agreement, then the ASC will be deemed equal to the PFx rate until an ASC can be established.

(iv) If a Utility's territory is transferred to a Public Power Entity that does not have a Residential Purchase and Sale Agreement, then no ASC will be established.

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.

(d) If Commission Accounts are later revised, renumbered, or added, such changes will be incorporated into the Table 1 and the Appendix 1 by reference. Bonneville will address such changes, including functionalization codes and escalation rules, in its ASC Review Process for the following Exchange Period.

18 CFR § 301.7

§ 301.7 Provisions for Public Power Entities

REP-participating Public Power Entities 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	

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:					
Distribution Plant	360-374	DIST		CD	
Energy Storage Plant:					
Energy Storage Plant	387-387.12	DIRECT	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	

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**		
Asset Retirement Costs for General Plant	399.1	PTD		CONSTANT	
Depreciation Reserve:					
Steam Production Plant	108	PROD		CONSTANT	
Nuclear Production Plant	108	PROD		CONSTANT	
Hydraulic Production Plant	108	PROD		CONSTANT	
Solar Production Plant	108	PROD		CONSTANT	
Wind Production Plant	108	PROD		CONSTANT	
Other Renewable Production Plant	108	PROD		CONSTANT	
Energy Storage Plant	108	PTD		CONSTANT	
Other Production Plant	108	PROD		CONSTANT	
Transmission Plant	108	TRANS		CONSTANT	
Distribution Plant	108	DIST		CONSTANT	
General Plant	108	GP		CONSTANT	
Amortization of Intangible Plant - Account 301	111	DIST		CONSTANT	
Amortization of Intangible Plant - Account 302	111	DIRECT	PTD	CONSTANT	
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	CONSTANT	

Table 1: Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization		Escalation Codes	Endnote
		Default	Optional		
BONNEVILLE POWER ADMINISTRATION 2026 Average System Cost Methodology Functionalization and Escalation Codes					
Amortization of Plant Held for Future Use	111	DIST		CONSTANT	
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT	
Amortization of Acquisition Adjustments	115	DIRECT	DIST	CONSTANT	
Cash Working Capital:					a/
Utility Plant:					
(Utility Plant) Held For Future Use	105	DIST		CONSTANT	
(Utility Plant) Completed Construction - not classified - Electric	106	PTD		CONSTANT	
Nuclear Fuel	120.2-120.6	PROD		NFUEL	
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT	
Acquisition Adjustments (Electric)	114	DIRECT	DIST	CONSTANT	
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	

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**		
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	
Stores Expense Undistributed	163	PTD		INF	
Prepayments	165	PTD		CONSTANT	
Derivative Instrument Assets	175	DIST		CONSTANT	
Less: Long-Term Portion of Derivative Assets	175	DIST		CONSTANT	
Derivative Instrument Assets – Hedges	176	DIST		CONSTANT	
Less: Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT	

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**		
Deferred Debits:					
Unamortized Debt Expenses	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 (Major only)	184	DIST		CONSTANT	
Temporary Facilities (Major only)	185	PTDG		CONSTANT	
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT	
Deferred Losses from Disposition of Utility Plant	187	DIRECT	DIST	CONSTANT	
Research, Development, and Demonstration Expenditures (Major only)	188	DIST		CONSTANT	
Unamortized Loss on Reacquired Debt	189	PTDG		CONSTANT	
Accumulated Deferred Income Taxes	190	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**		
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 Reacquired Debt	257	PTDG		CONSTANT	
Accumulated Deferred Income Taxes-Accel. Amort. Property	281	DIST		CONSTANT	
Accumulated Deferred Income Taxes-Other property	282	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**		
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	

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**		
Solar Power Generation					
Solar – Operation	558.1-558.5	PROD		OOPS	
Solar - Maintenance	558.6-558.11	PROD		OMN	
Wind Power Generation					
Wind – Operation	558.13-558.17	PROD		OOPS	
Wind - Maintenance	558.18-558.23	PROD		OMN	
Other Renewable Generation					
Other Renewable – Operation	559.1-559.4	PROD		OOPS	
Other Renewable - Maintenance	559.6-559.15	PROD		OMN	
Other Power Generation					
Other Power – Fuel	547	PROD		NATGAS	
Other Power - Operations (Excluding 547 - Fuel)	546-550.1	PROD		OOPS	
Other Power – Maintenance	551-554.1	PROD		OMN	
Other Power Supply Expenses					
Purchased Power (long term and intermediate term)	555	PROD		INF	

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**		
Purchased Power (short term)	555	PROD		See section 301.5.b.2	
Power Purchased for Storage Operations	555.1	PTD		CONSTANT	
Bundled environmental credits	555.2	PROD		CONSTANT	
Unbundled environmental credits	555.3	PROD		CONSTANT	
System Control and Load Dispatching	556	PROD		CONSTANT	
Other Expenses	557	PROD		CONSTANT	
Energy Storage Expenses: Operation	577.1-577.5	DIRECT	PTD	CONSTANT	k/
Energy Storage Expenses: Maintenance	578.1-578.7	DIRECT	PTD	CONSTANT	k/
Public Purpose Charges		DIRECT	DIST	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	

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 and Sales Expenses:					
Total Customer Accounts	901-905	DIST		CACNT	
Customer Service Supervision (Major only)	907	DIST		CSERV	
Customer assistance expenses (Major only)	908	DIST	DIRECT	CSERV	d/
Customer Service and Information (Major only)	909-910	DIST	DIRECT	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	LABOR		A&G	e-f/
Commission Approved Injuries & Damages		LABOR	DIRECT	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**		
Employee Pensions & Benefits	926	LABOR		A&G	
Franchise Requirements	927	DIST		A&G	
Regulatory Commission Expenses	928	DIST		A&G	
(Less) Duplicate Charges - Credit	929	PTDG		A&G	
General Advertising Expenses	930.1	DIST	DIRECT	A&G	
Miscellaneous General Expenses	930.2	DIST	DIRECT	A&G	
Rents	931	DIST		A&G	
Maintenance					
Maintenance of General Plant	935	GPM		A&G	
Depreciation and Amortization:					
Amortization of Intangible Plant (limited-term electric plant) Account 301	404	DIST		CONSTANT	
Amortization of Intangible Plant (other electric plant) - Account 301	405	DIST		CONSTANT	
Amortization of Intangible Plant (limited-term electric plant) - Account 302	404	DIRECT	PTD	CONSTANT	
Amortization of Intangible Plant (other electric plant) - Account 302	405	DIRECT	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**		
Amortization of Intangible Plant (limited-term electric plant) - Account 303	404	DIRECT	DIST	CONSTANT	
Amortization of Intangible Plant (other electric plant) - Account 303	405	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	
Solar Production Plant	403	PROD		CONSTANT	
Wind Production Plant	403	PROD		CONSTANT	
Other Renewable Production	403	PROD		CONSTANT	
Other Production Plant	403	PROD		CONSTANT	
Energy Storage Plant	403	DIRECT	PTD	CONSTANT	
Transmission Plant	403	TRANS		CONSTANT	
Distribution Plant	403	DIST		CONSTANT	
General Plant	403	GP		CONSTANT	
Common Plant – Electric	403 & 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**		
Depreciation Expense for Asset Retirement Costs	403.1	DIRECT		CONSTANT	
Amortization of Limited Term Electric Plant	404	DIRECT		CONSTANT	
Amortization of Plant Acquisition Adjustments (Electric)	406	DIRECT		CONSTANT	
Schedule 3A: Taxes					
FEDERAL:					
Income Tax (Included on Schedule 2)	409.1	DIST		CONSTANT	
Employment Tax	408.1	LABOR		WAGES	
Other Federal Taxes	408.1	DIST		CONSTANT	
STATE AND OTHER:					
Property (or In-Lieu)	408.1	PTDG		CONSTANT	
Unemployment	408.1	LABOR		WAGES	
State Income, B&O, etc.	409.1	DIST		CONSTANT	
Franchise Fees	408.1	DIST		CONSTANT	
Regulatory Commission	408.1	DIST		CONSTANT	
City/Municipal	408.1	DIST		CONSTANT	
Other	408.1	DIST		CONSTANT	
Schedule 3B: Other Included Items					

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 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	
Less: Loss from Disposition of Utility Plant	411.7	DIRECT	DIST	CONSTANT	
Gain from Disposition of Allowances	411.8	PROD		CONSTANT	
Less: Loss from Disposition of Allowances	411.9	PROD		CONSTANT	
Gains from disposition of environmental credits	411.11	PROD		CONSTANT	
Losses from disposition of environmental credits	411.12	PROD		CONSTANT	
Miscellaneous Nonoperating Income	421	DIRECT	PROD	CONSTANT	
Sale for Resale:					
Sales for Resale (long term and intermediate term)	447	PROD		INF	g/
Sales for Resale (short term)	447	PROD		See section 301.5.b.2	g/
Transmission for Sales for Resale		DIRECT			g/

Table 1: Functionalization and Escalation Codes

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

k/ See section 301.4.v

18 CFR PT. 301, APP. 1

Appendix 1 to Part 301--ASC Utility Filing Template

Bonneville Power Administration

ASC Methodology Part II

BPA Rules of Procedure for ASCs

DEPARTMENT OF ENERGY

BONNEVILLE POWER ADMINISTRATION

RULES OF PROCEDURE FOR BPA'S ASC REVIEW PROCESSES

XX 2026

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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 provide prior notice of the commencement date and conduct a kickoff workshop preceding the ASC Review Process. BPA will review all Utilities' ASCs concurrently in a public process.

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

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

6. PRESERVATION OF CONFIDENTIALITY

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

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

Confidential Information only to other Qualified Persons associated with the same party.

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

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

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

7. DURATION OF PROTECTION

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

8. DESTRUCTION AFTER PROCEEDING

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

9. ADDITIONAL PROTECTIONS

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

9.1.1. The parties and persons involved;

9.1.2. The exact nature of the information involved;

9.1.3. The exact nature of the relief requested;

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

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

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

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

ATTACHMENT B-1

CONFIDENTIALITY AGREEMENT

Docket Nos. [List all that apply]

I. Confidentiality Agreement

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

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

By: ______________________________ ______________________________

Signature Date

______________________________ ______________________________

Print Name Title

Persons Qualified Pursuant to Sections 2.1.3 and 4.2.3

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

By:

______________________________ ______________________________

Signature Date

______________________________ ______________________________

Print Name Title

______________________________ ______________________________

Employer Address

By:

______________________________ ______________________________

Signature Date

______________________________ ______________________________

Print Name Title

______________________________ ______________________________

Employer Address

CONFIDENTIALITY AGREEMENT

(*Extra Signature Page*)

Docket Nos. [List all that apply]

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