124 FERC ¶ 61,312
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 301

Docket Nos. EF08-2011-000 and RM08-20-000

Sales of Electric Power to the Bonneville
Power Administration; Revisions to Average System Cost Methodology

AGENCY: Federal Energy Regulatory Commission

ACTION: Interim Rule

SUMMARY: The Bonneville Power Administration (Bonneville) has submitted for the Federal Energy Regulatory Commission (Commission)'s approval a new methodology for determining the average system cost (ASC) of a utility's resources under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Bonneville requested that the Commission revise its regulations to incorporate the new methodology and to make the revised regulations effective October 1, 2008. On an interim basis, the Commission is conditionally revising its regulations governing the ASC methodology used by Bonneville in its Residential Exchange Program. The Commission also is requesting comments on whether, on a final basis, the Commission should approve the new ASC methodology proposed by Bonneville.

EFFECTIVE DATE: This interim rule is effective October 1, 2008.

COMMENT DATE: Comments on the interim rule are due [insert date that is 30 days after publication in the **FEDERAL REGISTER].**

ADDRESSES: You may submit comments on the interim rule, identified by Docket Nos. EF08-2011-000 and RM08-20-000, by one of the following methods:

- Agency web site: http://www.ferc gov. Follow instructions for submitting comments via the eFiling link found in the Comment Procedures Section of the preamble.
- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to the Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 20426. Please refer to the Comment Procedures Section of the preamble for additional information on how to file paper comments.

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher. Chairman:
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology	Docket Nos. EF08-2011-000 and RM08-20-000

INTERIM RULE

(Issued September 30, 2008)

1. The Bonneville Power Administration (Bonneville) has submitted for the Federal Energy Regulatory Commission (Commission)'s approval a new methodology for determining the average system cost (ASC) of a utility's resources under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).[1] Bonneville requested that the Commission revise its regulations to incorporate the new methodology and to make the revised regulations effective October 1, 2008. On an interim basis, the Commission is conditionally revising its regulations governing the ASC methodology used by Bonneville in its Residential Exchange Program. The Commission also is requesting comments on whether, on a final basis, the Commission should approve the new ASC methodology proposed by Bonneville.

[1] 16 U.S.C. 839(c)

Background

2. Section 5(c) of the Northwest Power Act provides for a Residential Exchange Program, which broadly speaking is designed to make the benefit of Bonneville's relatively low preference power rates available to residential customers of investor-owned utilities in the Pacific Northwest.[2] Although the Residential Exchange Program is available to any Pacific Northwest utility, the primary beneficiaries of the exchange are investor-owned utilities. Under the Residential Exchange Program, a utility may sell power to Bonneville at the average system cost of that utility's resources.[3] Bonneville then sells the same amount of power back to the utility at Bonneville's priority firm exchange rate.[4] The power exchange is generally viewed as a paper transaction.[5] In almost all instances, Bonneville makes a payment to the utility for the difference between the utility's average system cost and Bonneville's priority firm exchange rate, multiplied by the utility's residential and small farm load.

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[2] Id.

[3] 16 U.S.C. 839c(c)(1).

[4] Id. This rate is generally a lower rate.

[5] See CP Nat'l Corp. v. BPA, 928 F.2d 905, 907 **(**9th Cir. 1991) (quoting Public Utility Commissioner of Oregon v. BPA, 583 F. Supp. 752, 754 (D. Or. 1984)).

3. The Northwest Power Act does not define what constitutes the average system cost of a utility's resources.[6] Instead, the Act grants Bonneville's Administrator the authority to establish a methodology for determining an exchanging utility's average system cost through a stakeholder process in consultation with the Northwest Power Planning Council, Bonneville's customers, and appropriate State regulatory bodies in the region.[7] The Northwest Power Act directed the Administrator to exclude the following three types of costs from the average system cost: (1) the cost of additional resources in an amount sufficient to serve any new large single load of the utility, (2) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (3) any costs of any generating facility which is terminated prior to initial operation.[8] Outside these explicit exclusions, the Northwest Power Act is silent on the costs that may be included or excluded in the average system cost. Bonneville's Administrator decides what costs should be considered when calculating the average system cost, and what process should be used to make that determination.

4. The Commission's role in this exchange program is two-fold. First, under section 5(c)(7) of the Act, while Bonneville develops a methodology for

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[6] 16 U.S.C. 839c(c)(2).

[7] 16 U.S.C. 839c(c)(7).

[8] 16 U.S.C. 839c(c)(7)(A)-(C).

determining a utility's ASC (after consulting with various affected groups), the Commission must "review and approve" the methodology. Neither the statute nor its legislative history explain the nature of this review however.[9]

5. The Commission's second role in the exchange program arises from its Federal Power Act (FPA)[10] responsibility to review the wholesale sales rates of individual investor-owned utilities; the Commission reviews the rates for such sales from the investor-owned utilities to Bonneville based on the ASC methodology. The Commission's existing rules (18 CFR 35.30 and 35.31) provide that the Commission will approve under the FPA any sale to Bonneville that is based on correct application of an approved methodology.[11]

6. On July 14, 2008, Bonneville filed a revised ASC methodology to replace the current ASC methodology approved by the Commission on a final basis in 1984, and codified in part 301 of the Commission's regulations (July 2008 Filing).[12] In its July 2008 Filing (which was corrected on September 12, 2008),[13]

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[9] Methodology for Sales of Electric Power to Bonneville Power Administration, Order No. 400, FERC Stats. & Regs. 1 30,601 at 31,161 (1984), reh'g denied, Order No. 400-A, FERC 30 FERC ¶ 61,108 (1985).

[10] 16 U.S.C. 824, 824d, 824e.

[11] Order No. 400, FERC Stats. & Regs.1 30,601 at 31,161.

[12] 18 CFR Part 301.

[13] The July 2008 Filing was noticed in Docket No. EF08-2011-000 in the Federal Register, 72 FR 32633 (2008), with protests and interventions due on or before August 13, 2008. Timely motions to intervene and comments were filed

(continued...)

Bonneville states that this is the first revision to its ASC methodology in 24 years, and reflects changes in the energy industry that have transpired during that time.

7. Bonneville explains that the stakeholder process that resulted in this revised ASC methodology began in May of 2007, following two Ninth Circuit opinions that held that Bonneville exceeded its statutory authority when it entered into certain Residential Exchange Program Settlement Agreements, and remanded Bonneville's WP-02 wholesale power rates for improperly allocating the costs of the Residential Exchange Program Settlement Agreements to its preference customers.[14] Bonneville explains that it ceased making Residential Exchange Program payments following these 2007 decisions.

8. Bonneville states that, before it can provide Residential Exchange Program payments, it must re-establish the Residential Exchange Program. According to Bonneville, this requires the following: (1) negotiation of Residential Purchase and Sale Agreements; (2) establishment of a Priority Firm Exchange rate in a

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by Avista Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., Public Utility District No. 1 of Clark County, Washington, and the Public Utility District No. 1 of Grays Harbor County, Washington. The Public Power Council and the Public Utility District No. 1 of Snohomish County, Washington filed motions to intervene out of time. In addition, the Idaho Power Company filed comments and a partial protest. The Idaho Public Utilities Commission filed a notice of intervention and protest. Bonneville filed an answer to interested parties' comments and protests. Additionally, Bonneville filed an errata correction to its initial filing on September 12, 2008.

[14] See Portland General Elec. Co. v. BPA, 501 F.3d 1009 (9`" Cir. 2007); Golden NW Aluminum, Inc. v. Bonneville Power Admin., 501 F.3d 1037 (9th Cir. 2007).

Northwest Power Act section 7(i)[15] rate adjustment proceeding; and (3) calculation of utilities' respective average system costs under an ASC methodology. Bonneville notes that, in a separate Bonneville proceeding, it negotiated new Residential Purchase and Sale Agreements to be effective October 1, 2008. And, in another Bonneville proceeding, it developed a revised priority firm exchange rate that it will submit to the Commission in a separate docket for interim approval. Bonneville explains that it must ensure that an ASC methodology is in effect to determine exchanging utilities' average system costs to implement the Residential Exchange Program on October 1, 2008. Bonneville, therefore, requests the Commission to grant interim approval of the revised ASC methodology no later than October 1, 2008.

9. In its July 2008 Filing, Bonneville explains that the revised ASC methodology retains characteristics of the current ASC methodology. Bonneville explains, further, that the key differences are in how average system costs are calculated as well *as* the substance of the costs included and excluded from the average system cost calculation. Bonneville states that the revised ASC methodology adopts a streamlined approach to the average system cost calculations by using a different source of average system cost data, i.e., FERC Form No. 1 data, instead of state retail rate orders. Bonneville notes that, in addition, it proposes to adjust the average system costs less frequently. Bonneville

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[15] 16 U.S.C. 839e.

asserts that the revised ASC methodology allows each utility to file a single, combined average system cost for its entire within-region service territory as opposed to an average system cost for each state jurisdiction in which it operates.

10. Bonneville also explains that it is proposing to establish a two-year average system cost that will correspond with its two-year wholesale power rate periods. Bonneville explains, further, that utilities' average system costs will stay fixed except for pre-determined adjustments to reflect the costs of new resources incurred during the rate/exchange period. According to Bonneville, these features will lessen the number of average system costs filings reviewed by Bonneville and the Commission.

11. Bonneville explains that the revised ASC methodology also changes the average system cost treatment of certain costs. Bonneville states that it is allowing utilities to exchange a full return on equity (instead of the weighted cost of debt); the utility's marginal Federal income tax; and the utility's transmission plant costs. Bonneville requests Commission approval of this new ASC methodology.

Discussion

13. For the reasons discussed below, the Commission has determined to conditionally grant interim approval of Bonneville's new ASC methodology. We note, however, that the methodology must be further reviewed before final approval can be given; this review cannot be completed during the short time period in which the methodology has been before the Commission.

14. Interim approval is necessary to further the intent of the Northwest Power Act. An approved (by the Commission) ASC methodology is fundamental to the Residential Exchange Program found in section 5 of the Northwest Power Act The methodology defines the rates at which sales will be made to Bonneville which, when made, will permit exchanges to occur.

15. This warrants approval on an interim basis of Bonneville's revised ASC methodology. However, the Commission is obligated to review and approve the methodology in accordance with certain procedures and its responsibilities to protect the public interest, and the Commission has yet to finish its review of the proposed methodology. For these reasons, the approval granted here is interim only.

16. Moreover, such interim approval must be conditioned to ensure that the public interest is protected during the time period the interim approval is in place. The revised ASC methodology will affect rates paid by, and to, Bonneville. To the extent that the ASC methodology finally approved by the Commission differs from that filed by Bonneville in its July 2008 filing, and which is approved on an interim basis here, the rates paid may be different from the rate under the ASC methodology finally approved by the Commission. The Commission must be assured that any such difference can be corrected, through refund or surcharge, to the extent of the difference, should that be appropriate. To ensure this result, the

Commission grants interim approval only conditionally and subject to refund or surcharge.[16]

17. The Commission attaches this condition with the full awareness that by so doing, some uncertainty is injected into the exchange process. Rates paid may be too high or too low, depending upon the ASC methodology finally approved by the Commission. However, under the circumstances, some uncertainty is unavoidable. The Commission staff has completed a preliminary review of the methodology, however, and is satisfied that such uncertainty is minimal. Moreover the methodology is a product not only of a stakeholder process, which should serve to minimize any uncertainty, but also of notice and comment procedures. This provides good grounds for finding that, for purposes of interim approval, due process has been observed.[17]

Paperwork Reduction Act Statement

18. A Paperwork Reduction Act Statement is not required for this interim rule because the regulations adopt a methodology used by a federal power marketing administration, in this case Bonneville.

Environmental Analysis

19. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant

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[16] Order No. 400, FERC Stats. & kegs. ¶ 30,601 at 31,162.

[17] Id.

adverse effect on the human environment[18] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in these exclusions are Commission actions addressing proposed public utility rates and Commission confirmation, approval, and disapproval of rate filings submitted by federal power marketing administrations under the Northwest Power Act[19] The actions herein fall within this categorical exclusion in the Commission's regulations.

Regulatory Flexibility Act

20. The Regulatory Flexibility Act of 1980 (RFA)[20] generally requires a description and analysis of the effect that an interim rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

21. The Commission concludes that this interim rule will not have such an impact on a substantial number of small entities. Bonneville is a federal power marketing administration. And the investor-owned utilities which are participating

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[18] Regulations Implementing the National Environmental Policy Act, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[19] CFR 380.4(a)(15).

[20] 5 U.S.C. 601-12.

in the Residential Exchange Program are not small entities[21] Moreover, the number of utilities participating in the program is not substantial; only nine utilities whose rates are within the Commission's jurisdiction are participating in the program.

22. For these reasons, the Commission certifies under the RFA that this interim rule will not have a significant economic effect on a substantial number of small entities.

Comment Procedures

23. The Commission invites interested persons to submit comments on the matters and issues raised by the proposed revised ASC methodology. Comments are due [insert date that is 30 days after publication in the **FEDERAL REGISTER**].[22] Comments must refer to Docket Nos. EF08-2011-000 and RM08-20-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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[21] 5 U.S.C. § 602(3) citing section 3 of the Small Business Act, 15 U.S.C. § 632. Section 3 of the Small Business Act defines "small business concern" as a business which is independently owned and operated, and which is not dominant in its field of operation.

[22] All motions to intervene, comments, and protests, and all notices of intervention filed in Docket No. EF08-201 1-000 will be considered to have been filed in Docket No. RM08-20-000. All comments and protests filed in Docket No. EF08-2011-000 will be addressed in the final rule issued in Docket No. RM08-20-000. Intervenors in Docket No. EF08-201 1-000 wishing to file additional comments may do so.

24. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

25. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to the Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 40246.

26. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

Document Availability

27. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's home page http://www.ferc.gov and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 P.M Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

28. From the Commission's home page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the document number excluding the last three digits of this document in the docket number field.

29. User assistance is available for eLibrary and the Commission's web site during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesuppora@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at <public.referenceroom @ferc.gov>.

Effective Date

30. For the reasons discussed above, the Commission finds good cause under section 553(d)(3) of the Administrative Procedure Act[23] to make this rule effective immediately, rather than 30 days after publication in the Federal Register. The long-term impact of delaying early implementation of a new revised ASC methodology justifies its immediate effectiveness. This interim rule, therefore, will take effect on October 1, 2008.

[23] 5 U.S.C. 553(d)(3).

List of subjects in 18 CFR Part 301

Electric power rates; Electric utilities; Reporting and recordkeeping requirements

By the Commission.

(SEAL)

Nathan J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission amends part 301, Title 18, Chapter I of the Code of Federal Regulations, as follows:

1. Part 301 is revised to read as follows:

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.

§ 301.1 Applicability.

This section applies to the sales of electric power by any public utility to Bonneville pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839c(c).

§ 301.2 Definitions.

For purposes of this section, the following definitions apply:

(a) Account(s). The Accounts prescribed in the FERC Uniform System of Accounts.

(b) 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.

(c) 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).

(d) Average System Cost delta (ASC delta). The increase 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.

(e) 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.

(f) Average System Cost review process (ASC review process). The administrative proceeding conducted before Bonneville pursuant to Bonneville's ASC review procedures in which a Utility's ASC is determined.

(g) Base Period. The calendar year of the most recent Form 1 data.

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

(i) Contract High Water Mark (CHWM). The average MW amount used to define access to Tier 1-Priced Power. CHWM is equal to the adjusted historical load for each customer proportionately scaled to Tier 1 System Resources and adjusted for conservation achieved. The CHWM is specified in each eligible customer's CHWM Contract.

(j) Commission. The Federal Energy Regulatory Commission.

(k) Consumer-owned Utility. A public body or cooperative that is eligible to purchase preference power from Bonneville pursuant to section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b).

(l) Contract System Cost. The Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in, and subject to, the provisions of Appendix 1.

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).

(m) Contract System Load. The total regional retail load included in the most recently filed Form 1 or, for a Consumer-owned Utility, the total retail load from the most recent annual audited financial statement, as adjusted pursuant to the ASC Methodology.

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

(o) 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.

(p) Exchange Load. All usual residential, apartment, seasonal dwelling and farm electrical loads eligible for the Residential Exchange Program pursuant to the terms of a Utility's Residential Purchase and Sales Agreement.

(q) 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, 2008, through September 30, 2009. 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.

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

(s) Form 1. The annual filing submitted to the Federal Energy Regulatory Commission required by 18 C.F.R. § 141.1.

(t) Functionalization. The process of assigning a Utility's costs, revenues, debits and credits to the Production, Transmission, and Distribution/Other functions of the Utility.

(u) Global Insight. The company that provides the escalation factors identified in § 301.4(a)(3) that are used in the ASC forecasting model, or the successor or replacement of such company as determined by Bonneville.

(v) 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).

(w) Labor Ratios. The ratios that assign 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 Form 1. For Consumer-owned Utilities, comparable data will be utilized based on the cost-of-service study used as the basis for retail rates at the time of review.

(x) Net Requirements. The amount of Federal power that a Consumer-owned Utility is entitled to purchase from BPA pursuant to section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b).

(y) 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 Sale and Purchase Agreements with its Regional Power Sales Customers. 16 U.S.C. § 839a(13).

(z) Priority Firm Power. Priority Firm (PF) Power is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale to public bodies, cooperatives, and Federal agencies (under the PF Preference rate) and to utilities participating in the Residential Exchange Program (under the PF Exchange rate). Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase PF Power pursuant to their Residential Purchase and Sales Agreements with BPA. PF Power is not available to serve NLSLs. Deliveries of PF Power may be reduced or interrupted as permitted by the terms of the utilities' power sales contracts and/or Residential Purchase and Sales Agreements with BPA.

(aa) 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:

(1) Conservation programs in lieu of Utility conservation programs; or

(2) Acquisition of renewable resources.

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

(cc) Rate Period High Water Mark (RHWM). The amount used to define each customer's eligibility to purchase Tier 1 Priced Power for the relevant Rate Period, subject to the customer's Net Requirement expressed in average megawatts (aMW). RHWM is equal to the customer's CHWM as adjusted for changes in Tier 1 System Resources. The RHWM is determined for each eligible customer in the RHWM Process preceding each Bonneville wholesale power rate case.

(dd) Rate Period High Water Mark Process (RHWM Process). The process or processes where each eligible Consumer-owned Utility's RHWM is determined.

(ee) 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).

(ff) Residential Purchase and Sale 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.

(gg) 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, and ends on or about November 15 of the fiscal year prior to the fiscal year Bonneville implements a change in wholesale power rates.

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

(ii) Tier 1 Priced-Power. Priority Firm Power as defined in Bonneville's Tiered Rates Methodology.

(jj) Tier 1 System Resources. Resources as defined in Bonneville's Tiered Rates Methodology.

(kk) Tiered Rates Methodology (TRM). The long-term methodology established by Bonneville for the determination of tiered wholesale power rates.

(ll) Utility. A Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

§ 301.3 Filing Procedures.

(a) Bonneville's ASC Review Procedures.

(1) The procedures established by the 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.

(b) Exchange Period.

(1) 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.

§ 301.4 <u>Exchange Period Average System Cost Determination</u>.

(a) <u>Escalation to Exchange Period</u>.

(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 fiscal year for a one-year Rate Period/Exchange Period, and to the midpoint of the two-year period for a two-year Rate Period/Exchange Period to calculate Exchange Period ASCs.

(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) SMN– 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 Global Insight 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 Inflation as the replacement escalator.

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

(1) Long-term and intermediate-term sales for resale and power purchases. Bonneville will use the inflation escalator (INF) to escalate long-term and intermediate-term (as defined by the Commission) firm purchased power costs and long-term and intermediate-term sales for resale revenues.

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

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

(iii) The method described in paragraph (b)(2)(ii) of this section will be used to forecast the electric market price for power purchases needed to meet load growth not met by major resource additions, and to forecast the electric market price for any additional surplus power sales resulting from major resource additions.

(c) <u>Major resource additions and reductions and materiality thresholds</u>.

(1) 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) 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) new production or generating resource investments;

(ii) new transmission investments;

(iii) long-term generating contracts;

(iv) pollution control and environmental compliance investments relating to generating resources;

(v) long-term transmission contracts;

(vi) hydro relicensing costs and fees; and

(vii) plant rehabilitation investments.

(4) Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's ASC within an Exchange Period provided that the major resource addition or reduction results in a 2.5 percent or greater change in a Utility's Base Period ASC. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold,

provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.

(5) At the time the Utility submits its Appendix 1 filing, the Utility will provide its forecast of major new 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) Bonneville will calculate new transmission wheeling revenues associated with new transmission investment using the following formula:

TTWR = WR (before additions) * [(NTP (before additions) + NTA) / NTP (before additions)]

Where:

TTWR = Total transmission wheeling revenues

WR (before additions) = wheeling revenues (before additions)

NTP (before additions) = Net Transmission Plant (before additions)

NTA = new transmission additions

(7) The forecast of the major new resource 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.

(8) All major resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the midpoint of the Exchange Period.

(9) 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 (the ASC delta) at the midpoint of the Exchange Period.

(10) 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.

(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) BPA will escalate the cost 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) Bonneville will issue procedural rules to ensure the confidentiality of information provided by utilities regarding any new major resource additions as part of its review process. Bonneville will provide parties with an opportunity

to comment on the rules prior to their implementation in the review process. Failure to provide needed information may result in exclusion of the related costs from the Utility's ASC. However, load growth will be assumed to be met with purchases in the wholesale market, as described in paragraph (e) of this section. If the Utility fails to supply confidential resource data, it loses the difference between the cost of the resource and the price of electricity in the wholesale market.

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

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

(1) The Utility's forecast load growth will be met with electric market purchases priced at the Utility's forecast short-term purchased power price as determined in paragraph (b) of this section unless the Utility forecasts major resource additions.

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

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

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

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

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

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

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

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

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

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

(g) <u>ASC determination for Consumer-owned Utilities that elect to execute Regional Dialogue High Water Mark contracts</u>. For Consumer-owned Utilities that elect to execute Regional Dialogue CHWM contract Bonneville will use the following approach:

(1) Use the RHWM System Load as determined in the Tiered Rates Methodology process.

(2) Determine the RHWM Exchangeable Load (Residential/Small Farm Load).

(3) During the ASC review process, the Utility must submit the data necessary to determine the fully-allocated unit cost of resources in excess of the resource amounts used to calculate its CHWM.

(4) Calculate the Utility's total unadjusted Contract System Cost.

(5) Calculate a load growth credit, i.e., ((Current System Load minus RHWM System Load) * Unit costs from paragraph (g)(3) of this section).

(6) Total Exchange Contract System Cost = Total Unadjusted Contract System Cost minus load growth revenue credit from paragraph (g)(5) of this section.

(7) HWM Average System Cost = Total Exchangeable Contract System Cost/RHWM System Load.

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

§ 301.5 Changes in Average System Cost Methodology.

(a) The Administrator, at his or her discretion, or upon written request from three-quarters of the utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of Bonneville's preference customers, or from three-quarters of Bonneville's direct-service industrial customers may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, the Administrator may file the new ASC methodology with the Commission. However, 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.

(b) 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.

§ 301.6 Appendix 1 Instructions.

(a) 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 schedules and several supporting files that must be completed by the Utility in accordance with these instructions and the provisions of the endnotes following the schedules.

(b) Appendix 1 filings must be accompanied by an attestation statement of the Chief Financial Officer of the Utility or other responsible official who possesses the financial and accounting knowledge necessary to complete the attestation statement.

(c) The primary source of data for the investor-owned utilities' Appendix 1 filings is the Utility's prior year Form 1 filing with the Commission. Any items not applicable to the Utility must be identified.

(d) For Consumer-owned Utilities that do not follow the Commission's Uniform System of Accounts, filings must include reconciliation between Utility accounts and the items allowed as Contract System Cost. In addition, the cost-of-service report must be reviewed by an independent accounting or consulting firm. The cost-of-service report must be accompanied by a report from an independent accounting firm or consulting firm that outlines the review work that was performed in preparing the cost-of-service report along with an assurance statement that the information contained in the cost-of-service report is presented fairly in all material respects.

(e) The Appendix 1 template is available electronically at http://www.bpa.gov/corporate/flnance/ascm/, or its successor site. 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

(f) The filing Utility must reference and attach work papers, documentation, and other required information that supports costs and loads, including details of allocation and functionalization. All references to the

Commission's Accounts are the Commission's Uniform System of Accounts as of July 1, 2006, 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. If the Commission's Accounts are later revised or renumbered, any changes will be incorporated into the Appendix 1 by reference, except to the extent Bonneville determines that a particular change results in a change in the type of costs allowable for Residential Exchange Program purposes. In that event, Bonneville will address the changes, including escalation rules, in its review process for the following Exchange Period.

(g) Bonneville may require a Utility to account for all transactions with affiliated entities as though the affiliated 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)(1) A Utility operating in 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 1 filing must include details of the allocation.

(2) The allocation must exclude all costs of additional resources used to wheel loads outside the region, 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) A Utility must file an attestation statement with each Appendix 1 filing and supporting documentation for each Review Period.

§ 301.7 Average System Cost Methodology Functionalization.

(a) 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. The direct analysis must be consistent with the directions provided in this section.

(b) 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.

(c) 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 for that account without prior written 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.

(d) 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 function of the Utility. The only exception to this requirement is for

conservation-related costs. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. The analysis is subject to Bonneville review and approval.

(2) Bonneville will not allow utilities to use a combination of direct analysis and a prescribed functionalization method for the same Account. The utilities 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) Utilities that wish to include advertising and promotion costs related to conservation will use direct analysis. If a Utility records conservation costs in an Account that is normally 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. The Utility must submit with its ASC filing all work papers, documents, and other materials that demonstrate the functionalization contained in its direct analysis and assign costs based upon the actual and/or intended functional use of those items. Failure to submit the documentation will result in the entire account being

functionalized to Distribution/Other for all schedules with the exception of items included in Schedule 3B, Other Included Items, where certain accounts must be functionalized to Production as appropriate.