■ 3. Section 329.102 is amended by revising the introductory text to read as follows:

§ 329.102 Deposits described in § 329.1(b)(3).

This interpretive rule explains the proviso of § 329.1(b)(3).

* * * * *

Dated this 9th day of September 2009.

By order of the Board of Directors.

Federal Deposit Insurance Corporation.

Robert E. Feldman,

Executive Secretary.

[FR Doc. E9–22070 Filed 9–14–09; 8:45 am]

BILLING CODE 6714–01–P

transferable instruments for the purpose of making transfers to third parties—i.e., to hold deposits commonly called NOW accounts.

Paragraph (2) of 12 U.S.C. 1832(a) provides: ''Paragraph (1) shall apply only with respect to deposits or accounts which consist solely of funds in which the entire beneficial interest is held by one or more individuals or by an organization which is operated primarily for religious, philanthropic, charitable, educational, political, or other similar purposes and which is not operated for profit, and with respect to deposits of public funds by an officer, employee, or agent of the United States, any State, county, municipality, or political subdivision thereof, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, Guam, any territory or possession of the United States, or any political subdivision thereof.''

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 301

[Docket Nos. EF08–2011–000 and RM08–20–000; Order No. 726; 128 FERC ¶ 61,222]

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

Issued September 4, 2009.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission grants final approval to the revised methodology for determining the average system cost (ASC) used by Bonneville Power Administration in its Residential Exchange Program.

DATES: *Effective Date:* This final rule is effective October 15, 2009.

FOR FURTHER INFORMATION CONTACT:

Peter Radway (Technical Information), Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Phone: 202–502–8782, e-mail: *peter.radway@ferc.gov.*

Julia A. Lake (Legal Information), Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Phone: 202–502–8370, e-mail: *julia.lake@ferc.gov.*

SUPPLEMENTARY INFORMATION:

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

Order No. 726

Final Rule

Issued September 4, 2009

1. The Federal Energy Regulatory Commission grants final approval of the Bonneville Power Administration's (Bonneville) 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]

I. Background

2. Section 5(c) of the Northwest Power Act provides for a Residential Exchange Program, which is designed to make the benefits of Bonneville's relatively low preference power rates available to residential customers of investor-owned utilities in the Pacific Northwest. 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.[2] Bonneville then sells the same amount of power back to the utility at Bonneville's priority firm exchange rate.[3] The power exchange is generally viewed as a paper transaction.[4] 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.

3. The Northwest Power Act does not define what constitutes the average system cost of a utility's resources. Instead, the Northwest Power Act grants Bonneville's Administrator the authority to establish a methodology for determining and 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.[5] The Northwest Power Act, however, directs 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 cost of any generating facility which is terminated prior to initial operation.[6] 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 Northwest Power Act, while Bonneville develops a methodology for 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 explains the nature of this review.[7]

5. The Commission's second role in the exchange program arises from its Federal Power Act (FPA)[8] responsibility to review the wholesale sales rates of individual public utilities, essentially 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 accept under the FPA any sale to Bonneville that is based on application of an approved ASC methodology.[9]

6. On July 14, 2008, Bonneville filed a proposed revised ASC methodology to replace the then-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

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

[2] 16 U.S.C. 839c(c)(1).

[3] This rate is generally a lower rate.

[4] *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)).

[5] 16 U.S.C. 839c(c)(7).

[6] 16 U.S.C. 839c(c)(7)(A)–(C).

[7] *Methodology for Sales of Electric Power to Bonneville Power Administration,* Order No. 400, FERC Stats. & Regs. ¶ 30,601, at 31,161–62 (1984), *reh'g denied,* Order No. 400–A, 30 FERC ¶ 61,108 (1985).

[8] 16 U.S.C. 824, 824d, 824e.

[9] Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,161–62.

Filing).[10] In its July 2008 Filing (which was corrected on September 12, 2008),[11] Bonneville stated that this was the first revision to its ASC methodology in 24 years, and reflected changes in the energy industry that had transpired during that time.

7. In its July 2008 Filing, Bonneville explained that the revised ASC methodology retained characteristics of the then-current ASC methodology. Bonneville explained, further, that the key differences were how average system costs are calculated as well as the substance of the costs included and excluded from the average system costs calculation. Bonneville stated that the revised ASC methodology adopted a streamlined approach to the average system cost calculations by using a different source of average system cost data, *i.e.,* FERC Form 1 data, instead of state retail rate orders. Bonneville noted that, in addition, it proposed to adjust average system costs less frequently. Bonneville asserted that the revised ASC methodology allowed 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 operated.

8. Bonneville also explained that it was proposing to establish a two-year average system cost period that would correspond with its two-year wholesale power rate periods. Bonneville explained, further, that each utility's average system cost would stay fixed except for pre-determined adjustments to reflect the costs of new resources incurred during the rate/exchange period. According to Bonneville, this feature would lessen the number of average system cost filings reviewed by Bonneville and the Commission.

9. Bonneville explained that the revised ASC methodology also changed the average system cost treatment of certain costs. Bonneville stated that it was 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.

10. Bonneville requested Commission approval of this new ASC methodology by October 1, 2008 to coordinate with the initiation of the Residential Exchange Program.

11. On September 30, 2008, the Commission conditionally approved in an interim rule Bonneville's proposed ASC methodology. The Commission also requested comments on whether it should approve the ASC methodology on a final basis as proposed by Bonneville.[12]

II. Discussion

12. For the reasons discussed below, the Commission grants final approval of Bonneville's new ASC methodology, as amended, with minor editorial changes.

A. Introduction

13. Bonneville proposed an amended ASC methodology in its comments. Bonneville states that its amended 2008 ASC methodology comprises the following three main components: (1) Provisions related to the calculation of the Base Period average system cost (in amended §§ 301.8, 301.9, and the Appendix 1 Endnotes); (2) provisions relating to the escalation (or change) of the Base Period average system cost to the Exchange Period average system cost (amended § 301.5); and (3) provisions relating to Bonneville's average system review process and procedures (amended §§ 301.3, 301.4 and 301.7).

Comments

14. The Public Utility District No. 1 of Clark County, Washington and the Public Utility District No. 1 of Grays Harbor County, Washington (Districts) challenge Bonneville's calculation of average system cost in a different manner for investor-owned utilities and for consumer-owned utilities participating in the Residential Exchange Program.[13] The Districts argue that, under prior ASC methodologies, investor-owned utilities and consumer-owned utilities were able to include the same non-Federal resource costs and the same retail loads for the calculation of their average system costs. The Districts claim that now, in contrast, the investor-owned utilities can include the costs of all non-federal resources and their entire retail loads, and the consumer-owned utilities face limitations on their recovery of the costs of non-federal resources and limitations on their retail loads. The Districts challenge Bonneville's rationale offered to support this different treatment, *i.e.*, that allowing consumer-owned utilities to participate fully in Bonneville's Residential Exchange Program would frustrate its policy goal of tiering or separating the costs of existing Federal resources from future resource costs for purposes of setting its Priority Firm Rate. The Districts argue that all utilities must be treated in the same manner, and that Bonneville has other means to implement its policy goal of tiering its resource costs. The Districts, therefore, request the Commission to reject Bonneville's filing.

15. Idaho Public Utility Commission (Idaho PUC) supports Bonneville's revised ASC methodology. Idaho PUC, however, challenges the deemer mechanism [14] that is used in determining a utility's average system cost.[15] Idaho PUC notes that, when it challenged this mechanism in Bonneville's stakeholder process to develop this revised ASC methodology, Bonneville declined to consider the challenge because the mechanism is not, in fact, part of the ASC methodology, but rather is part of the Residential Purchase and Sales Agreements between Bonneville and its customers. Idaho PUC disagrees, and requests the

[10] *See* 18 CFR Part 301.

[11] 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 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 the comments and protests. Additionally, Bonneville filed an errata correction to its original filing on September 12, 2008 (September errata filing).

[12] Comments were due on or before November 10, 2008. *See* 73 FR 60,105 (Oct. 10, 2008). In response to a request by Bonneville the Commission subsequently provided an opportunity for reply comments. *See* Appendix A (providing a list of commenters). Bonneville filed an answer to the comments.

[13] For investor-owned utilities, the ASC methodology allows the costs of all non-Federal resources to be included in their average system cost calculations. Investor-owned utilities also are permitted to use their retail load to determine their average system cost. On the other hand, consumer-owned utilities that sign new power sales contracts with Bonneville that are offered under Bonneville's Regional Dialogue process are subject to limitations on the non-Federal resource costs and the retail loads that can be used to calculate their average system cost.

[14] A deemer provision is a contractual provision that dates from the 1981 Residential Purchase and Sales Agreement, which was the first contract that implemented Bonneville's Residential Exchange Program. The provision was designed to address the situation where an exchanging utility's average system cost falls below Bonneville's Power Firm Exchange rate, resulting in ''negative'' Residential Exchange Program benefits. Rather than have a utility pay Bonneville, the exchanging utility could ''deem'' its average system cost equal to the Power Firm Exchange Rate. The negative difference that would have otherwise been paid to Bonneville is then tracked in a separate ''deemer account.'' An outstanding balance in the deemer account is referred to as a ''deemer balance.'' An exchanging utility is required to pay off this balance through reductions in future positive Residential Exchange Program benefits before it can receive further Residential Exchange Program payments. Certain exchanging utilities accrued deemer balances under the 1981 Residential Purchase and Sales Agreements.

[15] Idaho Power also challenges the deemer mechanism for the same reasons as Idaho PUC.

Commission to reject use of the deemer mechanism.

Bonneville's Answer

16. Bonneville argues that the Districts mischaracterize the ASC methodology as applied to consumer-owned utilities. It asserts that eligible consumer-owned utilities may choose to exchange all of their eligible non-federal resources with Bonneville, provided they execute a Residential Purchase and Sales Agreement. It states, further, that it never proposed to exclude the costs of eligible, non-federal resources of consumer-owned utilities from the average system cost calculation for purchases under that agreement. Bonneville also argues that the ASC methodology excludes the non-federal resources of the consumer-owned utilities from the calculation of the average system cost only to the extent a consumer-owned utility chooses to purchase power from Bonneville in the future under a so-called Regional Dialogue High Water Mark Contract (CHWM contract) provided to Bonneville's preference customers under its Tiered Rates methodology.[16] Bonneville notes that the CHWM contract is just one type of power sales agreement that Bonneville will offer. Bonneville states that, only if the consumer-owned utilities want a power sales contract that is connected to the Tiered Rates methodology, must they agree to limit the resources they exchange with Bonneville.

17. Bonneville argues that the concerns of Idaho PUC and Idaho Power regarding the legality of the deemer provision are outside the scope of this rulemaking on the ASC methodology and should not be addressed in this proceeding. Bonneville asserts that the deemer provision is a provision in the Residential Purchase and Sales Agreement, and, as such, should be addressed in other forums. Bonneville adds that the Residential Purchase and Sales Agreement provisions are currently undergoing a stakeholder review process in another proceeding pending before Bonneville.

Commission Determination

18. Initially, the Commission grants Bonneville's request to amend proposed part 301, as requested by Bonneville in its comments on the interim rule. Bonneville's requested amendments to part 301 of the Commission's regulations, described in more detail below, revise and clarify Bonneville's ASC methodology and review process as it applies to Bonneville's customers. As Bonneville notes, it held a public workshop with its customers to discuss the amendments and requested comments from its customers. According to Bonneville, its customers did not object to the revisions in their comments, but did request further clarifications that it asserts it incorporated in its filing.

19. The Commission approves Bonneville's amended ASC methodology, with minor editorial changes, notwithstanding the Districts' objections. We note that, while the Districts complain of inconsistent treatment, the Districts also recognize that, under the statute, Bonneville has the authority to address with its customers, investor-owned utilities as well as consumer-owned utilities, which resources to include in its ASC methodology.[17] And the statute simply does not require the kind of consistency that Districts claim it does.[18] In any event, if consumer-owned utilities choose to execute Residential Purchase and Sales Agreements, then they will be entitled to the kind of consistency the Districts seek. Moreover, the Commission's role is limited to ''review[ing] and approv[ing]'' the ASC methodology.[19] As we noted in Order No. 400, Bonneville is entitled to ''considerable deference'' both in its interpretations of the Northwest Power Act and its policy judgments under that Act.[20] (The Commission's regulations also provide that the Commission will accept under the FPA any sales to Bonneville that are based on application of an approved ASC methodology.[21]) The Commission is approving the ASC methodology because it conforms to the provisions of the Northwest Power Act.[22] We find no compelling basis in the Districts' comments for arriving at a different result.

20. We also decline Idaho PUC's request that we reject use of the deemer mechanism. We find that Idaho PUC's challenge represents a collateral attack on Bonneville's Residential Purchase and Sales Agreements between Bonneville and its customers, where that mechanism is found. Those agreements are not the subject of this rulemaking proceeding.

B. Base Period Average System Cost Calculation

21. Bonneville states that amended §§ 301.8, 301.9 and the Appendix 1 Endnotes provide the process for calculating a utility's Base Period average system cost. The Base Period average system cost is an average system cost calculated from data available during the Base Period, *i.e.,* the calendar year of an investor-owned utility's most recent FERC Form 1, or a consumer-owned utility's similar financial information. According to Bonneville, the Base Period average system cost is calculated by populating the schedules in Appendix 1 with cost and revenue data from the utility. An investor-owned utility primarily will rely on its most recent FERC Form 1 as its source of data (consumer-owned utilities will rely on similar data), using supplemental information for some particular areas. Bonneville notes that the Appendix 1 tables (Excel spreadsheets) will automatically generate the utility's Base Period average system cost.

22. Bonneville states that amended § 301.8 of Bonneville's ASC methodology provides general instructions for completing Appendix 1. That section describes the sources of data that investor-owned utilities and consumer-owned utilities must use. It also describes the utility's duty to provide its work papers and other documentation substantiating its calculations. The section also requires the utility to file an attestation from its Chief Financial Officer regarding the data.

23. Bonneville states that amended § 301.9 and Table 1 of Bonneville's ASC

[16] The Tiered Rates methodology implements a new tiered rate structure with one set of rates (Tier 1) for public bodies, cooperatives and Federal agencies (preference customers) that recovers the costs of Bonneville's current generating system and programs, including the Residential Exchange Program. These customers will be limited to the amount of power than can be purchased at Tier 1 rates. Another set of rates (Tier 2) will be established to recover the costs of new generating resources. Preference customers will be able to purchase any requirements that remain after purchasing up to their maximum at Tier 1 rates. The Tiered Rates methodology is structured to keep separate the costs of resources whose costs are recovered through Tier 1 rates from the costs of resources whose costs are recovered through Tier 2 rates. Bonneville's Tiered Rates methodology is currently pending in Docket No. EL09–12–000.

[17] *See* 16 U.S.C. 839c(c)(7); *see* Districts comments at 6 (''the Northwest Power Act gives Bonneville the responsibility of developing the methodology for calculating the average system cost of each participating utility'').

[18] *See* 16 U.S.C. 839c(c)(1), (7).

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

[20] *See* Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,163–64 (discussing, *inter alia*, the deference owed to Bonneville as well as *Aluminum Co. of America* v. *Central Lincoln Peoples' Utility District,* 104 S. Ct. 2472, 2480–2483 (1984)); *accord Sales of Electric Power to Bonneville Power Administration, Metholology and Filing Requirements*, Order No. 337, FERC Stats. & Regs. ¶ 30,506, at 30,738–39 (1983).

[21] *See* 18 CFR 35.30 and 35.31; *accord* Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,161–62; Order No. 337, FERC Stats. & Regs. ¶ 30,506 at 30,738–39.

[22] *See* Order No. 337, FERC Stats. & Regs. ¶ 30,506 at 30,738 (Commission can disapprove proposed ASC methodology only if it is inconsistent with Northwest Power Act).

methodology describe how the individual cost and revenue items in the utility's Appendix 1 are divided into the Production, Transmission, and Distribution/Other categories. According to Bonneville, costs that are assigned to the Production and Transmission categories will be included in the utility's average system cost calculation, *i.e.*, in the Contract System Cost numerator of the average system cost equation. Costs assigned to the Distribution/Other category will not be included. Bonneville notes that, for the most part, the line items in the Appendix 1 will be automatically assigned to the Production, Transmission, and/or Distribution/Other categories by predefined ratios, referred to as functionalization [23] codes.

24. According to Bonneville, for certain Accounts in Appendix 1, the utility will have the option of not using the default functionalization code. Instead, it may conduct a more detailed analysis to assign costs or revenues to the Production, Transmission, or Distribution/Other categories. Bonneville refers to this analysis as a ''direct analysis.'' Bonneville states that Table 1 identifies the Accounts in Appendix 1 that may be evaluated under a direct analysis. Paragraphs (c) and (d) of amended § 301.9 require that a utility substantiate its direct analysis with documentation and other evidence, and that the utility, having opted to use a direct analysis on an Account, must continue to use a direct analysis on the Account in future Appendix 1 filings, unless Bonneville allows the utility to return to the default functionalization code.

25. Bonneville notes that the Appendix 1 schedules and ratio tables are, in some instances, subject to special rules or requirements as described in the Endnotes to Appendix 1. The Endnotes provide substantive information about how certain line items in Appendix 1 will be treated.

Comments

26. Commenters challenge Bonneville's decision to adjust a utility's base year data by escalating the utility's average system costs to the mid-point of Bonneville's rate period.[24]

Commission Determination

27. The Commission finds that commenters are challenging an element of Bonneville's ASC methodology that is beyond the Commission's scope of review of the methodology. As we have explained above, our role is a limited one—ensuring consistency with the Northwest Power Act. We are not otherwise authorized to challenge the Administrator's decisions relating to the specifics of the ASC methodology.[25] Moreover, Bonneville developed the amended ASC methodology through a stakeholder process with customers. The amended ASC methodology approved here represents the results of that collaboration. To the extent Bonneville and its customers find that any component of that ASC methodology needs further refinement, we anticipate that Bonneville and its customers will resolve the issue through further consultation as provided by the statute.

C. Exchange Period Average System Cost Determination

28. According to Bonneville, amended §§ 301.8, 301.9 and the Endnotes will be the core provisions it will use to determine a utility's average system cost. Bonneville notes that the Commission will rely on those sections to evaluate whether Bonneville's average system cost determinations are consistent with Bonneville's 2008 ASC methodology.

29. Bonneville explains that, once a utility's Base Period is calculated and Bonneville determines that the utility has properly functionalized all of its costs, certain line items of the utility's Appendix 1 are escalated to the beginning of, and then through, Bonneville's subsequent wholesale power rate period (referred to as the Exchange Period). According to Bonneville, this ''escalation step'' is the second major component of Bonneville's 2008 ASC methodology, and is a new feature unique to its 2008 ASC methodology. According to Bonneville, this ''escalation step'' reduces the administrative burden by limiting changes to a utility's average system cost once it is established in an average system cost review process.

30. Section 301.5 of the amended 2008 ASC methodology describes the method Bonneville and parties developed to calculate the utility's average system cost. Bonneville uses industry standard escalators to escalate certain line items in the utility's Appendix 1. Bonneville explains that, after the specified line items are escalated, the utility's average system cost is recalculated. According to Bonneville, the resulting average system cost, *i.e.,* the Exchange Period average system cost, is the average system cost Bonneville will use to determine the utility's Residential Exchange Program benefits during Bonneville's subsequent wholesale power rate period. Bonneville notes that the Exchange Period average system cost also is the average system cost that jurisdictional utilities file with the Commission for review.

31. Amended § 301.5 also outlines the limited ways in which a utility's average system cost may change during an Exchange Period. Bonneville states that its amended 2008 ASC methodology removes the connection between a utility's request for a retail rate change and a change in its average system cost, thereby limiting the administrative burden for both Bonneville and the Commission. Bonneville states that the only time a utility's average system cost may change once established for an Exchange Period is: (1) To account for major resource additions or reductions; or (2) to adjust for the loss or gain of service territory. Bonneville explains that, except for these limited circumstances, a utility's average system cost is locked-in until the beginning of Bonneville's next average system cost review process.

Comments

32. Commenters challenge core provisions of the ASC methodology that will be used to determine a utility's average system cost, including but not limited to the following: (1) Use of FERC Form 1 data as the basis for calculating a utility's average system cost; [26] (2) failure to include state income and revenue taxes in the average system cost determination, while including federal income taxes; [27] (3) failure to include a utility's regulatory fees in Account 928; [28] (4) failure to include replacement fuel for power (and replacement gas transportation) agreements as a major resource addition in ''new resource costs;'' [29] (5) treatment of requirement sales for resale in Account 447; [30] (6) inclusion of conflicting statements regarding the functionalization of customer expenses in Account 908; [31] and (7) failure to provide a methodology for determining average system costs for customer-owned utilities that elect to

[23] The term ''functionalization,'' as used here, refers to the process of assigning a utility's costs and revenues to the Production, Transmission, and Distribution/Other categories.

[24] *See, e.g.,* Avista comments at 4; Idaho Power comments at 5.

[25] *See supra* notes 19–22 and accompanying text.

[26] *See, e.g.,* APAC comments at 1–2.

[27] *See, e.g.,* WUTC comments at 6; Avista comments at 14–16; Idaho Power at 3–6.

[28] *See, e.g.,* WUTC comments at 7; Avista comments at 11; Idaho Power comments at 10.

[29] *See, e.g.,* Avista comments at 4–5; Idaho Power at 6–7.

[30] *See, e.g.,* Avista comments at 8; Portland General comments at 9; Idaho Power comments at 10.

[31] Avista comments at 9; Idaho Power comments at 11.

execute Regional Dialogue High Water Mark contracts.[32]

Commission Determination

33. The Commission finds that commenters are challenging elements of Bonneville's ASC methodology that are beyond the Commission's scope of review. As we have explained above, our role is a limited one—ensuring consistency with the Northwest Power Act. We are not otherwise authorized to challenge the Administrator's decisions relating to the specifics of the ASC methodology.[33] Moreover, Bonneville developed the amended ASC methodology through a stakeholder process with customers. The amended ASC methodology approved here represents the results of that collaboration. To the extent Bonneville and its customers find that any component of that ASC methodology needs further refinement, we anticipate that Bonneville and its customers will resolve the issue through further collaboration as provided by the statute.

D. Bonneville's Review of a Utility's Average System Cost Determination

34. Amended §§ 301.3, 301.4, and 301.7 provide the procedures and schedules Bonneville will use when reviewing a utility's average system cost. Bonneville explains that a utility is required to file an Appendix 1 with Bonneville by June of the fiscal year prior to the beginning of Bonneville's next wholesale power rate proceeding. Bonneville notes that it conducts its rate proceedings in the fall of the year prior to the expiration of its rates. Bonneville notes, further, that in the years it is not proposing to change wholesale power rates, utilities are required to file an informational Appendix 1 with Bonneville. These informational filings will be used by Bonneville for trend analysis only. According to Bonneville, these filings are not reviewed in an average system cost review process, and do not result in a change to the utility's average system cost.

35. Bonneville notes that, although historically it developed its average system cost review procedures as part of the ASC methodology consultation process, the Commission has previously found that it has no jurisdiction over these procedures, and has directed comments on these matters to Bonneville.[34] Bonneville, therefore, requests that, consistent with this past practice, §§ 301.3, 301.4, and 301.7 of the regulations established in the interim rule be removed.

Comments

36. Commenters challenge elements of the Bonneville's process for reviewing a utility's average system cost determination, including but not limited to the following: (1) Bonneville's decision to require utilities to file Appendix 1 annually using updated FERC Form 1 data; [35] and (2) Bonneville's failure to commit to limiting future Exchange Periods to two-year periods.[36]

Commission Determination

37. The Commission finds that commenters are challenging elements of Bonneville's process for reviewing a utility's average system cost determination that are beyond the Commission's scope of review. As we have explained, our role is a limited one—insuring consistency with the Northwest Power Act.[37] We are not otherwise authorized to challenge the Administrator's decisions relating to the specifics of the ASC methodology or the processes used to develop both that methodology and the resulting determinations of average system costs. Moreover, Bonneville developed the amended ASC methodology through a stakeholder process with customers. The amended ASC methodology approved here represents the results of that collaboration. To the extent Bonneville and its customers find that any component of Bonneville's process needs further refinement, we anticipate that Bonneville and its customers will resolve the issue through further collaboration as provided by the statute.

E. Relationship Between Bonneville's Tiered Rate

Methdology and ASC Methodology

38. In its comments, Bonneville states that amended § 301.5 contains provisions that relate to the interplay between its ASC methodology and its proposed Tiered Rates methodology. According to Bonneville, the Tiered Rates methodology implements a new tiered rate structure that will establish one set of rates (Tier 1) for public bodies, cooperatives and Federal agencies (preference customers) that recovers the costs of Bonneville's current generating system and programs, including the Residential Exchange Program. Bonneville notes that these customers will be limited as to the amount of power that can be purchased at Tier 1 rates. Bonneville states that another set of rates (Tier 2) will be established to recover the costs of new generating resources. According to Bonneville, preference customers will be able to purchase power for their requirements that remain after purchasing up to their maximum MW at Tier 1 rates. Bonneville states that its Tiered Rates methodology is structured to keep separate the costs of resources recovered through Tier 1 rates from the costs of resources recovered through Tier 2 rates. Bonneville states that resources whose costs are recovered through Tier 2 rates will serve the load growth of preference customers.

39. Bonneville explains that, to implement the Tiered Rate methodology, it is now offering preference customers a new power sales agreement, a Regional Dialogue High Water Mark Contract, for power sales beginning in FY 2012. Bonneville notes that, for those preference customers that choose to execute this contract, there will be certain restrictions on the resources that these preference customers may exchange with Bonneville, identified in amended § 301.5(g). According to Bonneville, these restrictions are necessary to ensure that the separate ''cost pooling'' concept of tiered rates is maintained. Bonneville states that the Tiered Rate methodology features in its ASC methodology will only affect preference customers that execute this type of contract.

40. Bonneville notes that, although the Commission does not have jurisdiction over its average system cost determination for preference customers, those provisions of its ASC methodology will be used in its review of preference customers' average system costs. Bonneville, therefore, requests the Commission to retain these provisions in its final rule to maintain the continuity of its ASC methodology and for ease of reference for both Bonneville and its preference customers.

Comments

41. APAC notes that § 301.5(g) of the Commission's regulations incorporates the Tiered Rate methodology and the determination of High Water Marks.[38] APAC states that Tiered Rate methodology is still being finalized. APAC argues that, in that proceeding, it objected to the legality of the Tiered Rate methodology, arguing that it exceeded Bonneville's statutory

[32] *See, e.g.,* Avista comments at 12; Idaho Power comments at 14.

[33] *See supra* notes 19–22 and accompanying text.

[34] *See* Order No. 337, FERC Stats. & Regs. at ¶ 30,506 at 30,738.

[35] *See, e.g.,* Avista comments at 5; Idaho Power comments at 7.

[36] *See, e.g.,* Avista comments at 7; Idaho Power comments at 9.

[37] *See supra* notes 19–22 and accompanying text; *accord* Order No. 337, FERC Stats. & Regs. ¶ 30,506 at 30,738.

[38] *See* APAC comments at 2.

authority. Also, in that proceeding, APAC states that it challenged the determination of High Water Marks under the Tiered Rate methodology, arguing that certain industrial loads were not properly characterized. APAC requests the Commission not to grant approval for the ASC methodology in this proceeding until the Tiered Rate methodology is finalized by Bonneville and reviewed by the Commission.

Commission Determination

42. We decline to adopt APAC's request. APAC's arguments relate to the Tiered Rate methodology; that methodology is not the subject of this rulemaking proceeding. Bonneville's references to the Tiered Rate methodology in this rulemaking proceeding relate only to the interplay between the Tiered Rate methodology and the ASC methodology established in this final rule. That is, this ASC methodology final rule does not revise the Tiered Rate methodology. It merely specifies how the two methodologies will work in conjunction with one another. We note, further, that, since APAC's comments were filed in this proceeding, Bonneville filed its Tiered Rate methodology for Commission review.[39] To the extent that APAC objects to the Tiered Rate methodology, those objections are more appropriately raised in that proceeding.

III. Section-By-Section Description of Proposed Bonneville Amendments

43. In its comments on the interim rule, Bonneville submits proposed revisions and additions that are described in more detail below. We approve these revisions and additions, with minor editorial changes, as reflected in the regulatory text adopted here.

A. Section 301.1—Applicability

44. Bonneville requests the Commission to replace the language originally approved by the Commission for § 301.1 of the interim rule with the regulatory language that defined applicability prior to the interim rule. Bonneville believes that that language is more appropriate because its procedures for determining an average system cost should not be included in the Commission's final rule approving its ASC methodology.

B. Section 301.2—Definitions

45. Bonneville requests that the Commission add several definitions. Specifically, Bonneville requests the following terms be defined: Accounts; Average System Cost delta; Average System Cost forecast model; Average System Cost review process; Consumer-owned Utility; Direct Analysis; Escalator; Exchange Load; Functionalization; Global Insight; Net Requirements; Priority Firm Power; Rate Period; Rate Period High Water Mark Process (RHWM Process); RHWM Exchange Load; RHWM System Resources; Tier 1 Priced-Power; Tier 1 System Resources; and Tiered Rates Methodology. Bonneville notes that, in addition, it has clarified existing definitions and added statutory citations.

C. Section 301.3—Filing Procedures

46. Bonneville requests the Commission to remove the regulatory text in § 301.3(a)–(h). Bonneville explains that these regulations largely describe, in detail, its filing procedures during the transitional period (*i.e.,* FY 2009 and FY 2010–11), its ASC methodology review procedure filing requirements and instructions to exchanging utilities, its filing procedures, the utility's attestation responsibilities, and the process of determining and curing patently deficient filings. Going forward, according to Bonneville, a simple reference to its procedures will be sufficient for the Commission's regulations.[40]

D. Original § 301.4—Bonneville's ASC Methodology Review Process

47. Bonneville requests the Commission to delete § 301.4 as originally promulgated in the interim rule because it describes Bonneville's ASC review procedures and processes that the Commission does not have jurisdiction to review.

E. New § 301.4—Exchange Period Average System Cost Determination

1. Section 301.4(a)—Escalation to Exchange Period

48. Bonneville requests the Commission to revise the regulatory text to include the following: (1) Add a statement at the beginning of the section to explain the objective being met with the section; (2) to revise the description of the ''escalation codes'' to clarify the codes and the source of data for the codes; and (3) incorporate corrections made in its errata filing in September 2008.

2. Section 301.4(b)—Calculation of Sales for Resale and Power Purchases

49. Bonneville requests the Commission to revise the name of this subsection to clarify that the purpose of the subsection is to describe its ASC methodology for calculating the utility's sales for resale and power purchase, and to add headers to make it apparent which paragraphs apply to long-term/intermediate sales for resale and power purchases versus short-term sales for resale and power purchases. In addition, Bonneville proposes adding additional language to this subsection to clarify the provisions in this subsection.

3. Section 301.4(c)—Major Resource Additions and Reductions and Materiality Thresholds

50. Bonneville explains that amended § 301.4(c) is designed to calculate changes in average system cost when a utility obtains new resources or loses an existing resource. Bonneville proposes that language be added to § 301.4(c)(1) to clarify that a major resource addition or reduction must meet the criteria in § 301.5(c)(3), and meet the materiality test in § 301.4(c)(4). Bonneville also proposes added language and renumbered paragraphs in § 301.5(c) to clarify the existing regulatory text.

4. Section 301.4(d)—Forecasted Contract System Load and Exchange Load

51. Bonneville proposes minor revisions to § 301.4(d) and proposes to insert a sentence that was in its original filing but was left out of the interim rule approved by the Commission.

5. Section 301.4(e)—Load Growth Not Met by Major Resource Additions

52. Bonneville proposes minor textual changes to § 301.4(e)(1) and (e)(2). Bonneville also proposes to add language to § 301.4(e)(3) to provide greater detail and clarity regarding how surplus power from a major resource addition will be treated in Bonneville's average system cost forecast model.

6. Section 301.4(f)—Changes to Service Territory

53. Bonneville proposes minor clarifying corrections throughout § 301.4(f) to make the subsection more specific, describing in greater detail that the utility must file two Appendix 1s, and clarifying that the average system cost discussed in this section is the Base Period average system cost.

[39] *See United States Department of Energy—Bonneville Power Administration*, Docket No. EL09–12–000.

[40] The language adopted is similar to the language used for the prior ASC methodology. *See* 18 CFR 301.1(d).

7. Section 301.4(g)—Average System Cost Determination for Consumer-Owned Utilities That Elect To Execute Rate Period High Water Mark Contracts

54. Bonneville proposes to revise § 301.4(g) to use defined terms from its Tiered Rates Methodology, to change the order of the steps in §§ 301.4(g)(3) and (g)(4), and to combine the steps in §§ 301.4(g)(3) and (g)(5) into a new step in § 301.4(g)(4) to clarify calculation of the costs that will be excluded from the utility's average system cost.

8. Section 301.4(h)—Filing of Appendix 1

55. Bonneville proposes minor corrections throughout this subsection.

F. Section 301.5—Changes in Average System Cost Methodology

56. Bonneville proposes minor corrections throughout this section.

G. Original § 301.6—Sample Timeline Review Procedures

57. Bonneville requests the Commission to delete § 301.6 of the interim rule because the provisions are outside the purview of the Commission's review. Bonneville notes, however, that it will retain this section in its ASC review procedures.

H. New § 301.6—Appendix 1 Instructions

58. Bonneville proposes minor corrections to this section.

I. Section 301.7—Average System Cost Methodology Functionalization

59. Bonneville proposes revisions to this section to include the following: (1) Title correction; (2) addition of references to ''revenues, debits or credits'' throughout the section; (3) deletion of a sentence in § 301.9(d)(1) and addition of language to clarify that Accounts with conservation-related costs could be reviewed under a direct analysis subject to certain provisions; (4) deletion of ambiguous language in § 301.9(d)(2); (5) division of § 301.9(d)(3) into §§ 301.9(d)(3) and 301.9(d)(4); and (6) addition of a reference to ''conservation costs'' and deletion of a reference to ''Transmission and/or Distributor/Other'' in redesignated § 301.9(d)(4).

J. Table 1—Functionalization and Escalation Codes

60. Bonneville proposes to update the functionalization codes and make additional changes that will make the table consistent with § 301.5(b)(1) of the ASC methodology.

K. Appendix 1—ASC Utility Filing Template

61. Bonneville proposes the following revisions in Appendix 1: (1) Change the title of the template to ''ASC Utility Filing Template''; (2) incorporate errata corrections; (3) replace the phrase ''Residential Purchase Sales Agreement'' with the phrase ''ASC Utility Filing Template.''

L. Appendix 1 Endnotes

62. Bonneville proposes the following revisions in Appendix 1 Endnotes: (1) Add the phrase ''return on equity (ROE);'' and (2) delete Endnote K.[41]

M. Chief Financial Officer Attestation

63. Bonneville notes that the Commission did not include this attestation in its interim rule. Bonneville states that it agrees with the Commission's decision because this attestation relates to its average system cost review process and not to the Commission's review of the utility's ASC. Bonneville states that it will retain this attestation as a component of its average system cost review procedures.

IV. Paperwork Reduction Act Statement

64. A Paperwork Reduction Act Statement is not required for this final rule because the regulations approve a methodology used by a Federal power marketing administration, in this case Bonneville.

V. Environmental Analysis

65. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[42] 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 various statutes and regulations including the Northwest Power Act.[43] The actions taken here fall within this categorical exclusion in the Commission's regulations.

VI. Regulatory Flexibility Act

66. The Regulatory Flexibility Act of 1980 (RFA)[44] generally requires a description and analysis of the effect that a rule will have on small entities or a certification that a rule will not have a significant economic impact on a substantial number of small entities.

67. The Commission concludes that this final rule will not have a significant economic impact on a substantial number of small entities. Bonneville is a Federal power marketing administration. And the investor-owned utilities which are participating in the Residential Exchange Program and which, as public utilities under the FPA, make ASC-related filings with the Commission are not small entities.[45] Moreover, the number of public utilities participating in the program is not substantial; only nine public utilities, whose rates are within the Commission's jurisdiction, are participating in the program.

VII. Document Availability

68. 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 Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

69. 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.

70. 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 *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *publicreferenceroom@ferc.gov.*

[41] Endnote K does not appear in the interim rule. Bonneville proposed including Endnote K in its September 2008 errata filing. Since the Commission is accepting Bonneville's revised regulatory text, further specific action by the Commission is not needed.

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

[43] 18 CFR 380.4(a)(15).

[44] 5 U.S.C. 601–12.

[45] 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.

VIII. Effective Date

Given that this final rule establishes the methodology that Bonneville Power Administration will apply to determine average system costs, and thus what Bonneville will pay, this final rule meets the exception provisions of 5 U.S.C. 804(3)(A). This final rule is effective October 15, 2009.

List of Subjects in 18 CFR Part 301

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Kimberly D. Bose,

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

Authority: 16 U.S.C. 839–839h.

§ 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).

§ 301.2 Definitions.

For purposes of this section, the following definitions apply:

Account(s). The Accounts prescribed in the Commission's Uniform System of Accounts in part 101 of this chapter.

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 before Bonneville under Bonneville's ASC review procedures in which a Utility's ASC is determined.

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

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

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.

Commission. Federal Energy Regulatory Commission.

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

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 provision 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).

Contract System Load. The total regional retail load included in the most recently filed FERC 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.

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.

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, 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.

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

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

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

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 that company, as determined by Bonneville.

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 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 FERC 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.

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

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).

Priority Firm Power. Priority Firm Power is electric power (capacity and energy) that Bonneville will make continuously available for direct consumption or resale to public bodies, cooperatives, and Federal Agencies (under the Priority Firm Preference rate) and to Utilities participating in the Residential Exchange Program (under the Priority Firm Exchange rate). Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power under their Residential Purchase and Sales Agreements with Bonneville. Priority Firm Power is not available to serve New Large Single Loads. Deliveries of Priority Firm 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 Bonneville.

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

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

(b) Acquisition of renewable resources.

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

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.

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

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

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

RHWM Exchange Load. The Exchange Load as determined in section 20 of the Residential Purchase and Sales Agreement.

RHWM System Resources. The Rate Period High Water Mark (RHWM) as calculated in section 4.2.1 of the Tiered Rates Methodology plus the resource amounts used in calculating a customer's Contract High Water Mark (CHWM).

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

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

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

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

§ 301.3 Filing procedures.

(a) *Bonneville's ASC review procedures.* The procedures 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.

(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.

§ 301.4 Exchange Period Average System Cost determination.

(a) *Escalation to Exchange Period.*

(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) 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 Global Insight as the source of data for the escalation codes indentified in paragraph (a)(3) of this section, except for the NATGAS and CONSTANT codes. For the NATGAS code identified in paragraph (a)(3)(xiii)

of this section, Bonneville will calculate the escalation rate using Bonneville's most current forecast of natural gas prices. The code CONSTANT in paragraph (a)(3)(iv) of this section indicates that no escalation to the Account will be made.

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

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

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

(b) *Calculation of sales for resale and power purchases*—

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

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

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

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

(A) The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three 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 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 calculated in paragraph (b)(2)(ii)(B) of this section will be escalated at the same rate as Bonneville's electric market price forecast.

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

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

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

(1) 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) Transmission investments;

(iii) Long-term generating contracts;

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

(v) Long-term transmission contracts;

(vi) Hydroelectric 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 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:

$$TTWR = WR\ (\text{before additions}) * [(NTP\ (\text{before additions}) + NTA)/NTP\ (\text{before additions})]$$

Where:

TTWR = total transmission wheeling revenues
WR (before additions) = wheeling revenues (before additions)
NTA = new transmission additions
NTP (before additions) = Net Transmission Plant (before additions)

(7) 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.

(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 (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) 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) Bonneville will issue procedural rules to ensure the confidentiality of information provided by Utilities regarding any major resource additions or reductions 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 major resource additions.* All forecast load growth not met by major resource additions will be met by purchased power at the forecasted utility-specific, short-term purchased power price.

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) Determine the RHWM Exchange Load.

(3) Calculate the Utility's Contract System Cost as described in the ASC Methodology.

(4) Determine the fully allocated cost of resources used to meet Contract System Load that is not met by:

(i) The lesser of the Utility's RHWM or Forecast New Requirement, plus

(ii) Existing Resources for CHWM (as defined in the Tiered Rates Methodology).

(5) RHWM Contract System Cost = Contract System Cost minus fully allocated cost of resources (from paragraph (g)(4) of this section).

(6) RHWM Average System Cost = RHWM Contract System Cost (from paragraph (g)(5) of this section)/RHWM System Resource (from paragraph (g)(1) of this section).

(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, 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.

§ 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 with 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 FERC Form 1 filings 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, and must be accompanied by a report from that independent accounting 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/finance/ascm/*. 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 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. 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 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.

(2) 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) 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 method 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/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 (d)(4) 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. 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. 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.

Table 1 to Part 301—Functionalization and Escalation Codes

BILLING CODE 6717–01–P

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Schedule 1: Plant Investment/Rate Base				
Intangible Plant:				
Intangible Plant - Organization	301	DIST		CONSTANT
Intangible Plant - Franchises and Consents	302	DIRECT	PTD	CONSTANT
Intangible Plant - Miscellaneous	303	DIRECT	DIST	CONSTANT
Production Plant:				
Steam Production	310-317	PROD		CONSTANT
Nuclear Production	320-326	PROD		CONSTANT
Hydraulic Production	330-337	PROD		CONSTANT
Other Production	340-347	PROD		CONSTANT
Transmission Plant:				
Transmission Plant	350-359.1	TRANS		CONSTANT
Distribution Plant:				
Distribution Plant	360-374	DIST		CD
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
Communication Equipment	397	PTD		CONSTANT
Miscellaneous Equipment	398	PTD		CONSTANT
Other Tangible Property	399	DIRECT	PTD	CONSTANT
Asset Retirement Costs for General Plant	399.1	PTD		CONSTANT
Depreciation Reserve:				
Steam Production Plant	108	PROD		CONSTANT
Nuclear Production Plant	108	PROD		CONSTANT
Hydraulic Production Plant	108	PROD		CONSTANT
Other Production Plant	108	PROD		CONSTANT
Transmission Plant	108	TRANS		CONSTANT
Distribution Plant	108	DIST		CONSTANT
General Plant	108	GP		CONSTANT
Amortization of Intangible Plant - Account 301	111	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	111	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	CONSTANT
Mining Plant Depreciation	108	PROD		CONSTANT
Amortization of Plant Held for Future Use	111	DIST		CONSTANT
Capital Lease - Common Plant	108	DIRECT		CONSTANT
Leasehold Improvements	108	DIRECT	DIST	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
In-Service: Depreciation of Common Plant	108	DIRECT		CONSTANT
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT
Amortization of Acquisition Adjustments	115	DIRECT		CONSTANT
Depreciation and Amortization Reserve (Other)		DIRECT	N/A	CONSTANT
Cash Working Capital:				
(Utility Plant) Held For Future Use	105	DIST		CONSTANT
(Utility Plant) Completed Construction - Not Classified	106	PTD		CONSTANT
Nuclear Fuel	120.2-120.6	PROD		NFUEL
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT
Common Plant		DIRECT	N/A	CONSTANT
Acquisition Adjustments (Electric)	114	DIRECT	DIST	CONSTANT
Other Property and Investments:				
Investment in Associated Companies	123.1	DIRECT	DIST	CONSTANT
Other Investment	124	DIST		CONSTANT
Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Current and Accrued Assets:				
Fuel Stock	151	PROD		COAL
Fuel Stock Expenses Undistributed	152	PROD		CONSTANT
Plant Materials and Operating Supplies	154	PTD		INF
Merchandise (Major Only)	155	DIST		INF
Other Materials and Supplies (Major only)	156	DIST		INF
EPA Allowance Inventory	158.1	PROD		CONSTANT
EPA 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
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 (Electric)	183	DIST		CONSTANT
Preliminary Natural Gas Survey and Investigation Charges	183.1	DIST		CONSTANT
Other Preliminary Survey and Investigation Charges	183.2	DIST		CONSTANT
Clearing Accounts	184	DIST		CONSTANT
Temporary Facilities	185	PTDG		CONSTANT
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT
Deferred Losses from Disposition of Utility Plant	187	DIRECT	N/A	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Research, Development, and Demonstration Expenditures	188	DIST		CONSTANT
Unamortized Loss on Reacquired Debt	189	PTDG		CONSTANT
Accumulated Deferred Income Taxes	190	DIST		CONSTANT
Liabilities and Other Credits (Comparative Balance Sheet):				
Derivative Instrument Liabilities	244	DIST		CONSTANT
Less: Long-Term Portion of Derivative Instrument Liabilities	244	DIST		CONSTANT
Derivative Instrument Liabilities – Hedges	245	DIST		CONSTANT
Less: Long-Term Portion of Derivative Inst Liabilities–Hedges	245	DIST		CONSTANT
Customer Advances for Construction	252	DIST		CONSTANT
Other Deferred Credits	253	DIRECT	DIST	CONSTANT
Other Regulatory Liabilities	254	DIRECT	DIST	CONSTANT
Accumulated Deferred Investment Tax Credits	255	DIST		CONSTANT
Deferred Gains from Disposition of Utility Plant	256	DIRECT	N/A	CONSTANT
Unamortized Gain on Reacquired Debt	257	PTDG		CONSTANT
Accumulated Deferred Income Taxes-Accel. Amort.	281	DIST		CONSTANT
Accumulated Deferred Income Taxes-Property	282	DIST		CONSTANT
Accumulated Deferred Income Taxes-Other	283	DIST		CONSTANT
Schedule 3: Expenses				
Power Production Expenses:				
Steam Power Generation				
Steam Power – Fuel	501	PROD		COAL
Steam Power - Operations (Excluding 501 - Fuel)	500-509	PROD		SOPS
Steam Power – Maintenance	510-515	PROD		SMN
Nuclear Power Generation				
Nuclear – Fuel	518	PROD		NFUEL
Nuclear - Operation (Excluding 518 - Fuel)	517-525	PROD		NOPS
Nuclear – Maintenance	528-532	PROD		NMN
Hydraulic Power Generation				
Hydraulic – Operation	535-540.1	PROD		HOPS
Hydraulic – Maintenance	541-545.1	PROD		HMN
Other Power Generation				
Other Power – Fuel	547	PROD		NATGAS
Other Power - Operations (Excluding 547 - Fuel)	546-550.1	PROD		OOPS
Other Power – Maintenance	551-554.1	PROD		OMN
Other Power Supply Expenses				
Purchased Power (long term and intermediate term)	555	PROD		INF
Purchased Power (short term)	555	PROD		See section 301.4.b.2
System Control and Load Dispatching	556	PROD		CONSTANT
Other Expenses	557	PROD		CONSTANT
BPA REP Reversal	555	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Public Purpose Charges		DIRECT		See Section 301.4.a.6
Transmission Expenses:				
Transmission of Electricity by Others (Wheeling)	565	TRANS		INF
Total Operations less Wheeling	560-567.1	TRANS		TOPS
Total Maintenance	568-574	TRANS		TMN
Distribution Expense:				
Total Operations	580-589	DIST		DOPS
Total Maintenance	590-598	DIST		DMN
Customer and Sales Expenses:				
Total Customer Accounts	901-905	DIST		CACNT
Customer Service and Information	906-907	DIST		CSERV
Customer assistance expenses (Major only)	908	DIST		CSERV
Customer Service and Information	909-910	DIST		CSALES
Total Sales Expense	911-917	DIST		CSALES
Administration and General Expense:				
Operation				
Administration and General Salaries	920	LABOR		A&G
Office Supplies & Expenses	921	LABOR		A&G
(Less) Administration Expenses Transferred - Credit	922	LABOR		A&G
Outside Services Employed	923	LABOR		A&G
Property Insurance	924	PTDG		A&G
Injuries and Damages	925	LABOR		A&G
Employee Pensions & Benefits	926	LABOR		A&G
Franchise Requirements	927	DIST		A&G
Regulatory Commission Expenses	928	DIST		A&G
(Less) Duplicate Charges - Credit	929	PTDG		A&G
General Advertising Expenses	930.1	DIST		A&G
Miscellaneous General Expenses	930.2	DIST		A&G
Rents	931	DIST		A&G
Transportation Expenses (Non Major)	933	DIST		A&G
Maintenance				
Maintenance of General Plant	935	GPM		A&G
Depreciation and Amortization:				
Amortization of Intangible Plant - Account 301	404	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	404	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	404	DIRECT	DIST	CONSTANT
Steam Production Plant	403	PROD		CONSTANT
Nuclear Production Plant	403	PROD		CONSTANT
Hydraulic Production Plant - Conventional	403	PROD		CONSTANT
Hydraulic Production Plant - Pumped Storage	403	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Other Production Plant	403	PROD		CONSTANT
Transmission Plant	403	TRANS		CONSTANT
Distribution Plant	403	DIST		CONSTANT
General Plant	403	GP		CONSTANT
Common Plant – Electric	403 & 404	DIRECT	N/A	CONSTANT
Depreciation Expense for Asset Retirement Costs	403.1	DIRECT	N/A	CONSTANT
Amortization of Limited Term Electric Plant	404	DIRECT	N/A	CONSTANT
Amortization of Plant Acquisition Adjustments (Electric)	406	DIRECT	N/A	CONSTANT
Schedule 3A: Taxes				
FEDERAL:				
Income Tax (Included on Schedule 2)	409.1	DIST		CONSTANT
Employment Tax	408.1	LABOR		WAGES
Other Federal Taxes	408.1	DIST		CONSTANT
STATE AND OTHER:				
Property (or In-Lieu)	408.1	PTDG		CONSTANT
Unemployment	408.1	LABOR		WAGES
State Income, B&O, etc.	409.1	DIST		CONSTANT
Franchise Fees	408.1	DIST		CONSTANT
Regulatory Commission	408.1	DIST		CONSTANT
City/Municipal	408.1	DIST		CONSTANT
Other	408.1	DIST		CONSTANT
Schedule 3B: Other Included Items				
Other Included Items:				
Regulatory Debits	407.3	DIRECT	DIST	CONSTANT
Regulatory Credits	407.4	DIRECT	PROD	CONSTANT
Gain from Disposition of Utility Plant	411.6	DIRECT	PROD	CONSTANT
Loss from Disposition of Utility Plant	411.7	DIRECT	DIST	CONSTANT
Gain from Disposition of Allowances	411.8	PROD		CONSTANT
Loss from Disposition of Allowances	411.9	PROD		CONSTANT
Miscellaneous Nonoperating Income	421	DIRECT	PROD	CONSTANT
Sale for Resale:				
Sales for Resale (long term and intermediate term)	447	PROD		INF
Sales for Resale (short term)	447	PROD		See section 301.4.b.2
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

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Labor Ratios				
Labor Ratio Input:				
Production		PROD		WAGES
Transmission		TRANS		WAGES
Distribution		DIST		WAGES
Customer Accounts		DIST		WAGES
Customer Service and Informational		DIST		WAGES
Sales		DIST		WAGES
Administrative & General		PTD		WAGES

Appendix 1 to Part 301—ASC Utility Filing Template

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST		-	-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD	-	-	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST	-	-	-	-
Total Intangible Plant					$	$	$	$ -
Production Plant:								
Steam Production	204-207	310-317	PROD		0	-	-	-
Nuclear Production	204-207	320-326	PROD		0	-	-	-
Hydraulic Production	204-207	330-337	PROD		0	-	-	-
Other Production	204-207	340-347	PROD		0	-	-	-
Total Production Plant					$	$	$	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS		0	-	-	-
Total Transmission Plant					$	$	$ -	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST		0	-	-	-
Total Distribution Plant					$	$	$	$ -
General Plant:								
Land and Land Rights	204-207	389	PTD		0	-	-	-
Structures and Improvements	204-207	390	PTD		0	-	-	-
Furniture and Equipment	204-207	391	LABOR		0	-	-	-
Transportation Equipment	204-207	392	TD		0	-	-	-
Stores Equipment	204-207	393	PTD		0	-	-	-
Tools and Garage Equipment	204-207	394	PTD		0	-	-	-
Laboratory Equipment	204-207	395	PTD		0	-	-	-
Power Operated Equipment	204-207	396	TD		0	-	-	-
Communication Equipment	204-207	397	PTD		0	-	-	-
Miscellaneous Equipment	204-207	398	PTD		0	-	-	-
Other Tangible Property	204-207	399	DIRECT	PTD	0	-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD		0	-	-	-
Total General Plant					$	$	$	$
Total Electric Plant In-Service *(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*					$	$	$	$ -

Schedule 1

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:						0		
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD		0	-	-	-
Nuclear Production Plant	219	108	PROD		0	-	-	-
Hydraulic Production Plant	219	108	PROD		0	-	-	-
Other Production Plant	219	108	PROD		0	-	-	-
Transmission Plant (i)	219	108	TRANS		0	-	-	-
Distribution Plant	219	108	DIST		0	-	-	-
General Plant	219	108	GP		0	-	-	-
Amortization of Intangible Plant - Account 301	200	111	DIST		0	-	-	-
Amortization of Intangible Plant - Account 302	200	111	DIRECT	PTD	-	-	-	-
Amortization of Intangible Plant - Account 303	200	111	DIRECT	DIST	-	-	-	-
Mining Plant Depreciation	219	108	PROD		0	-	-	-
Amortization of Plant Held for Future Use	200	111	DIST		0	-	-	-
Capital Lease - Common Plant	219	108	DIRECT		0			
Leasehold Improvements	200-201	108	DIRECT	DIST	0	-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT		0	-	-	-
Amortization of Other Utility Plant (a)	200-201	111	DIRECT	DIST	0	-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT		0	-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
<u>Total Depreciation and Amortization Reserve</u>					$ -	$ -	$ -	$ -
<u>Total Net Plant</u> *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*					$	$	$	$ -

Schedule 1

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation:							
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST		0	-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD		0	-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST		0	-	-	-
Common Plant	356 & 356.1		DIRECT		0	-	-	-
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST	0	-	-	-
Total					$ -	$ -	$ -	$ -
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST	0	-	-	-
Other Investment	110-111	124	DIST		0	-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST		0	-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST		0	-	-	-
Total					$ -	$ -	$ -	$ -
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD		0	-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD		0	-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD		0	-	-	-
Merchandise (Major Only)	110-112	155	DIST		0	-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST		0	-	-	-
EPA Allowance Inventory	110-112	158.1	PROD		0	-	-	-
EPA Allowances Withheld	110-112	158.2	PROD		0	-	-	-
Stores Expense Undistributed	110-111	163	PTD		0	-	-	-
Prepayments	110-111	165	PTD		0	-	-	-
Derivative Instrument Assets	110-111	175	DIST		0	-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST		0	-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST		0	-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST		0	-	-	-
Total					$ -	$ -	$ -	$ -

Schedule 1

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG		0	-	-	-
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST	0	-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST	0	-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST	0	-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST		0	-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST		0	-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST		0	-	-	-
Clearing Accounts	110-111	184	DIST		0	-	-	-
Temporary Facilities	110-111	185	PTDG		0	-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST	0	-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT		0			
Research, Development, and Demonstration Expenditures	110-111	188	DIST		0	-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG		0	-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST		0	-	-	-
Total					$ -	$ -	$ -	$ -
Total Assets and Other Debits					$ -	$ -	$ -	$ -

Schedule 1

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilities								
Derivative Instrument Liabilities	112-113	244	DIST		0	-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST		0	-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST		0	-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST		0	-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST		0	-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST	0	-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST	0	-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST		0	-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT		0			
Unamortized Gain on Reacquired Debt	112-113	257	PTDG		0	-	-	-
Accumulated Deferred Income Taxes-Accel. Abort.	112-113	281	DIST		0	-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST		0	-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST		0	-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ -	$ -	$ -	$ -
Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)								

Schedule 1

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	-	-	-	-
Total Transmission O&M (i)	-	-	-	-
Total Distribution O&M	-	-	-	-
Total Customer & Sales	-	-	-	-
Total Administrative and General O&M	-	-	-	-
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	-	-	-	-
Revised Total O&M Expenses	$ -	$ -	$ -	$ -
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	$ -	$ -	$ -	$ -

Schedule 1A

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

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

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:
Multi-Jurisdiction Investor-Owned Utility Return Calculation:
Consumer-Owned Utility Return Calculation:
Rate of Return :

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order
Note: Multi-jurisdictional utilities must begin on Page 2
Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%
Federal Income Tax Factor
*((ROR – (Embedded Cost of Debt * (Debt / (Total Capital))) * ((Federal Tax Rate / (1- Federal Tax Rate))*

Federal Income Tax Adjusted Weighted Cost of Capital
(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

Schedule 2

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

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

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	Amount	Percent	Embedded	Weighted	Allocation	Weighted	State Allocation
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$						

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
Total						

Schedule 2

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

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

Multi-Jurisdiction Investor-Owned Utility Return Calculation ***(continued)***

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%

Federal Income Tax Factor

*{(ROR (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				
*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

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

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD			-	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (h)			DIRECT					
Total Production Expense					$ -	$ -	$ -	$ -
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS			-	-	-
Total Maintenance	320-323	568-574	TRANS			-	-	-
Total Transmission Expense					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:

End of Year Report Period:

ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Distribution Expense:								
Total Operations	320-323	580-589	DIST			-	-	-
Total Maintenance	320-323	590-598	DIST			-	-	-
Total Distribution Expense					$ -	$ -	$ -	$ -
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST			-	-	-
Customer Service and Information	320-323	906-907	DIST			-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIST					
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ -	$ -	$ -	$ -
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR			-	-	-
Office Supplies & Expenses	320-323	921	LABOR			-	-	-
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed	320-323	923	LABOR			-	-	-
Property Insurance	320-323	924	PTDG			-	-	-
Injuries and Damages	320-323	925	LABOR			-	-	-
Employee Pensions & Benefits	320-323	926	LABOR			-	-	-
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses	320-323	930.1	DIST			-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					[redacted]	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ -	$ -	$ -	$ -
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD			-	-	-
Transmission Plant (i)	336	403	TRANS			-	-	-
Distribution Plant	336	403	DIST			-	-	-
General Plant	336	403	GP			-	-	-
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ -	$ -	$ -	$ -
Total Operating Expenses					$ -	$ -	$ -	$ -
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3A Items: Taxes

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, et.	262	409.1	DIST		-	-	-
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST		-	-	-
TOTAL STATE AND OTHER TAXES				$ -	$ -	$ -	$ -
TOTAL TAXES				$ -	$ -	$ -	$ -

Schedule 3A

BONNEVILLE POWER ADMINSTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327						
LF	326-327						
IF	326-327						
SF	326-327						
LU	326-327						
IU	326-327						
OS	326-327						
EX	326-327						
NA	326-327						
AD	326-327						
TOTAL		$ -	-	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Sold	Settlement Total	MWh Sold	Settlement Total	MWh Sold
RQ	310-311						
LF	310-311						
IF	310-311						
SF	310-311						
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		$ -	-	$ -	-	$ -	-

3 YEAR
PP OSS Worksheet

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3B Other Included Items

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD			-	-	-
Total Sales for Resale					$ -	$ -	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD			-	-	-
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD		-	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ -	$ -	$ -	$ -
Total Other Included Items *(Total Other + Total Sales for Resale + Total Other Revenue)*					$ -	$ -	$ -	$ -

Schedule 3B

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses (From Schedule 3)	$	$	$	$
Federal Income Tax Adjusted Return on Rate Base (From Schedule 2)	$	$	$	$
State and Other Taxes (From Schedule 3a)	$	$	$	$
Total Other Included Items (From Schedule 3b)	$	$	$	$
Total Cost	$	$	$	$

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

Schedule 4

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

Contract System Cost			
Production	$ -		
Transmission	$ -		NLSL Fully Alloc. Cost ($/MWh)
(Less) New Large Single Load Costs (d)	$ -		
Total Contract System Cost	$ -		
Contract System Load (MWh)			
Total Retail Load			
(Less) New Large Single Load			
Total Retail Load (Net of NLSL) (d)	0		Distribution Losses (%)
Distribution Loss (f)	0		0
Total Contract System Load	0		
Average System Cost $/MWh	$0		

Schedule 4

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Customer Accounts	354-355	
Customer Service and Information	354-355	
Sales	354-355	
Administrative and General	354-355	
TOTAL Operation		$0
Maintenance		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Administrative and General	354-355	
TOTAL Maintenance		$0
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	0
Transmission (Total of lines 17 and 27)	354-355	0
Distribution (Total of lines 18 and 28)	354-355	0
Customer Accounts (From line 20)	354-355	0
Customer Service and Information (From line 20)	354-355	0
Sales (From line 21)	354-355	0
Administrative and General (Total of lines 22 and 29)	354-355	0
TOTAL Operation and Maintenance		$0

Salaries

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
Labor Ratio Input:						
	Production	PROD	$ -	$ -	$ -	$ -
	Transmission	TRANS	-	-	-	-
	Distribution	DIST	-	-	-	-
	Customer Accounts	DIST	-	-	-	-
	Customer Service and Informational	DIST	-			
	Sales	DIST	-	-	-	-
	Administrative & General	PTD	-	-	-	-
Total Labor			$ -	$ -	$ -	$ -
	LABOR RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
GP	**General Plant Ratio**					
	Land and Land Rights	PTD	$ -	$ -	$ -	$ -
	Structures and Improvements	PTD	-	-	-	-
	Furniture and Equipment	LABOR	-	-	-	-
	Transportation Equipment	TD	-	-	-	-
	Stores Equipment	PTD	-	-	-	-
	Tools and Garage Equipment	PTD	-	-	-	-
	Laboratory Equipment	PTD	-	-	-	-
	Power Operated Equipment	TD	-	-	-	-
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	Other Tangible Property	DIRECT	-	-	-	-
	Asset Retirement Costs for General Plant	PTD	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	GENERAL PLANT RATIO		0%	0%	0%	0%

Ratios

BONNEVILLE POWER ADMINISTRATION

ASC Utility Filing Template

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	-	-	-	-
	Other Production	PROD	-	-	-	-
	Total Production Plant		-	-	-	-
	Transmission Plant	TRANS	-	-	-	-
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTD RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Rati**					
	PTD Total		$ -	$ -	$ -	$ -
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	-	-	-	-
	Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
	General Plant Total		-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTDG RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ -	$ -	$ -	$ -
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	TD RATIO		0%	0%	0%	0%

Ratios

BONNEVILLE POWER ADMINISTRATION
ASC Utility Filing Template
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ -	$ -	$ -	$ -
	Furniture and Equipment	LABOR	-	-	-	-
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	GPM RATIO		0%	0%	0%	0%

SUMMARY RATIO TABLE

		Production	Transmission	Distribution
Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	0.00%	0.00%	0.00%
Maintenance of General Plant	GPM	0.00%	0.00%	0.00%
Labor Ratios	LABOR	0.00%	0.00%	0.00%
Production, Transmission, Distribution	PTD	0.00%	0.00%	0.00%
Production, Transmission, Distribution, General	PTDG	0.00%	0.00%	0.00%
Transmission, Distribution	TD	0.00%	0.00%	0.00%

Ratios

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

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

b/ The overall rate of return (ROR) to be applied to a Utility's Exchange Period rate base as shown in Appendix 1 must be equal to its weighted cost of capital (WCC), including debt, preferred stock and equity, from its most recently approved Regulatory Body Rate Order. 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.

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

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

The sum of the FIT Adder plus the ROE equals the Federal income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal 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.

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.

c/ A tax-exempt Utility may include in-lieu taxes up to an amount that is comparable, for each unit of government paid in-lieu taxes, with taxes that would have been paid by a non-tax exempt utility to that unit of government. In no event will the Utility's regional total be greater than the actual amount paid or the amount used to determine the total revenue requirement. In-lieu taxes must be functionalized according to the PTDG ratio.

d/ The cost of additional resources sufficient to serve any New Large Single Load (NLSL) that was not contracted for, or committed to, prior to September 1, 1979, is to be determined as follows:

(1) To the extent that any NLSLs are served by dedicated resources at the cost of those resources, including applicable transmission;

(2) In the amount that NLSLs are not served by dedicated resources, at Bonneville's New Resources (NR) rates as established from time to time pursuant to section 7(f) of the Northwest Power Act, and as applicable to the Utility, and applicable Bonneville transmission charges if transmission costs are excluded in the determination of Bonneville's NR rate, to the extent those costs are recovered by the Utility's retail rates in the applicable Jurisdiction; and

(3) To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of the excess load will be determined by multiplying the kilowatt-hours not served under paragraphs (d)(1) and (d)(2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all resources and long term power purchases (five years or more in duration), as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period, exclusive of the following resources and purchases: (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to section 5(c) of the Northwest Power Act; (c) resources sold to Bonneville, pursuant to section 6(c)(1) of the Northwest Power Act; (d) dedicated resources specified in endnote d(1) of this Methodology; (e) resources and purchases committed to the Utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the Utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases must be priced at the average cost of transmission during the Exchange Period.

The paragraphs (d)(1) through (d)(3) will determine the Base Period cost of resources used to serve NLSLs. Bonneville will escalate the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

i. Escalate the components of the Base Period fully allocated resource costs to the Exchange Period using the general method for escalation of all Base Period costs.

ii. Adjust the projected resource costs by the projected transmission costs.

iii. Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

iv. The cost to serve NLSLs will change when the ASC changes due to resource additions/retirements.

v. The Exchange Period NLSL load will equal the Base Period NLSL load.

e/ 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 can be measured using one of the following 3 methods:

Method 1, Distribution Loss Study: 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.

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

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

i. Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.

ii. From this 5-year total system loss factor, subtract the loss factor for Bonneville's transmission system.

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

f/ 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, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and Public Purpose Charge.

g/ 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.

h/ 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.

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.

i/ If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using the Commission's seven factor test contained in Order 888, as amended by Order 890, and its FERC Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its FERC Form 1 filing. However, if a Utility is not required to file a FERC Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission. Alternatively, the Direct Analysis may use the Commission's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

j/ All revenues associated with the production and transmission function of a Utility will be functionalized to production or transmission respectively.

Note: The following Appendix will not be published in the *Code of Federal Regulations.*

Appendix—List of Commenters

Association of Public Agency Customers (APAC)
Avista Corporation (Avista)
Idaho Power Company (Idaho Power)
Idaho Public Utilities Commission (Idaho PUC)
PacifiCorp
Pacific Northwest Investor-Owned Utilities (IOU)
Portland General Electric Company (Portland General)
Public Utility District No. 1 of Clark County, Washington and Public Utility District No. 1 of Grays Harbor County, Washington, Public Utility District No. 1 of Snohomish County, Washington (Districts)
Puget Sound Energy, Inc. (Puget Sound)
Washington Utilities and Transportation Commission (WUTC)

[FR Doc. E9–21946 Filed 9–14–09; 8:45 am]
BILLING CODE 6717–01–C

DEPARTMENT OF JUSTICE

28 CFR Part 0

[Docket No. AG Order No. 3108–2009]

The Attorney General's Advisory Committee of United States Attorneys

AGENCY: Department of Justice.

ACTION: Final rule.

SUMMARY: This rule amends the Department of Justice regulation concerning the Attorney General's Advisory Committee of United States Attorneys. The amendments will provide the Attorney General greater flexibility in determining the size of the Committee, and will provide that the Attorney General will select the Committee's leadership.

DATES: *Effective Date:* September 15, 2009.

FOR FURTHER INFORMATION CONTACT: Norman Wong, Deputy Director and Counsel to the Director, Executive Office for United States Attorneys, Department of Justice, 950 Pennsylvania Avenue, Washington, DC 20530 (202) 514–2121.

SUPPLEMENTARY INFORMATION: This regulation recognizes that the United States Attorneys, as Presidential appointees having responsibilities mandated by Congress (28 U.S.C. 547), should be afforded an appropriate and formal means for contributing to the development of Department of Justice policies and procedures. The Attorney General's Advisory Committee of United States Attorneys ("Committee") aids the improvement of communication between federal and state law enforcement officials, the promotion of greater consistency in the application of legal standards, and the improvement of the criminal justice system at all levels of government. Under the existing regulation, the Committee is composed of fifteen members designated by the Attorney General, and the Committee is charged with selecting its leadership. Under the revised regulation, the Attorney General will determine the number of Committee members and will select from the membership a chairperson and vice-chairperson. The United States Attorney for the District of Columbia will serve as an *ex officio* member.

Administrative Procedure Act

This rule is a rule of agency organization and procedure, and relates to the internal management of the Department of Justice. It is therefore exempt from the requirements of notice and comments and a delayed effective date. 5 U.S.C. 553(b), (d).

Regulatory Flexibility Act

The Attorney General, in accordance with the Regulatory Flexibility Act (5 U.S.C. 605(b), has reviewed this regulation and by approving it certifies that this regulation will not have a significant economic impact on a substantial number of small entities because it pertains to personnel and administrative matters affecting the Department. Further, a Regulatory Flexibility Analysis was not required to be prepared for this final rule since the Department was not required to publish a general notice of proposed rulemaking for this matter.