SUBCHAPTER L—REGULATIONS FOR FEDERAL POWER MARKETING ADMINISTRATIONS

PART 300—CONFIRMATION AND APPROVAL OF THE RATES OF FEDERAL POWER MARKETING ADMINISTRATIONS

AUTHORITY: 16 U.S.C. 825s, 832–8321, 838–838k, 839–839h; 42 U.S.C. 7101–7352; 43 U.S.C. 485–485k.

SOURCE: Order 382, 49 FR 25235, June 20, 1984, unless otherwise noted.

Subpart A—General Provisions

§ 300.1 Applicability and definitions.

(a) *Applicability*. This part sets forth procedures governing the filing, review and disposition of the rate schedules for the sale or transmission of power and energy established by the Alaska, Bonneville, Southeastern, Southwestern and Western Area Power Administrations. Except as otherwise provided by rule or order, the Commission's general rules of practice and procedure (part 385 of this chapter) will apply to any filings, hearings or other procedures under this part, as applicable.

(b) *Definitions*. For purposes of this part, the following definitions apply:

(1) *Administrator* means the administrator of a power marketing administration.

(2) *Electric service* means any transmission or sale of electric power and energy, including capacity sales, energy sales, firm power sales, transmission services, or any combination of these services, and the utilization, by means of ownership, contractual arrangements, leasing, or other arrangements, of any facility to provide such sales or services.

(3) *Historic period* means the period commencing with the date of first commercial operation of a powerplant or transmission facility and ending on the last day of the latest year for which actual cost data are available, provided that the period does not end more than 18 months before the date on which the Administrator tenders the rate schedule for filing with the Commission, or such longer period requested by the Deputy Secretary of Energy or Administrator and granted by the Commission.

(4) *Initial capital investment* means the cost of acquisition or construction of a power facility or non-power facility which has been assigned to be repaid from the power revenues, including but not limited to any cost of planning, design, land acquisition, construction, interest during construction, and testing incurred before the date on which the facility becomes operational or revenue-producing.

(5) *Power repayment study or PRS* means a study of the annual repayment of production and transmission investments and other costs through the application of revenues during the repayment period.

(6) *Proposed rate approval period* means the period for which confirmation and approval of the rate schedules is requested. This period must not exceed five years.

(7) *Rate schedule* means a statement describing:

(i) Type of service to which the rate is to be applied;

(ii) Rates and charges for, or in connection with, electric service; and

(iii) Classifications and other provisions which directly affect such rates and charges.

(8) *Rate test or cost evaluation period* means a period, commencing with the end of the historic period, as defined in paragraph (b)(3) of this section, and continuing through the proposed rate approval period as defined in paragraph (b)(6) of this section, during which future estimates of costs and revenues should be modified by the Administrator to reflect changing conditions.

(9) *Replacement* means any substitution of a unit of property with another unit of like character.

[Order 382, 49 FR 25235, June 20, 1984, as amended by Order 323–B, 52 FR 20709, June 3, 1987]

§ 300.2 Informal conference.

The Administrator or a designee may confer with Commission staff prior to submitting an application under subpart B, with respect to the appropriate form and content of such application.

Subpart B—Filing Requirements

§ 300.10 Application for confirmation and approval.

(a) *General provisions*—(1) *Contents of filing*. Any application under this subpart for confirmation and approval of rate schedules must include, as described in this section a letter of request for rate approval, a form of notice suitable for publication in the FEDERAL REGISTER in accordance with the specifications in § 385.203(d) of this chapter, the rate schedule, a statement of revenue and related costs, the order, if any, placing the rates into effect on an interim basis, the Administrator's Record of Decision or explanation of the rate development process, supporting documents, a certification, and technical supporting information and analysis. The form of notice shall be on electronic media as specified by the Secretary.

(2) *Incorporation of information by reference*. Any information required under this subpart that has previously been submitted to the Commission in substantially the same form as specified in this section may be incorporated by reference only.

(3) *Time of filing*. (i) Rate schedules put into effect on an interim basis by the Secretary of the Department of Energy, or a designee, and filed for final Commission approval must be filed not later than five days after interim approval is granted.

(ii) Rate schedules of the Bonneville Power Administration for which interim approval by the Commission is requested must be filed not later than 60 days in advance of the proposed effective date.

(iii) Rate schedules for which interim approval is not requested must be filed not later than 180 days in advance of the proposed effective date.

(4) *Electronic filing*. All material must be filed electronically in accordance with the requirements of § 35.7 of this chapter.

(b) *Letter of request for rate approval*. A letter of request for rate approval must contain the following information:

(1) A description of the period for which Commission approval is requested, delineated by an effective date and an expiration date, and, for the Bonneville Power Administration, a request, if any, for interim approval of the rates;

(2) A brief description of the proposed rates and charges under existing and proposed rate schedules and the expected changes, if any, in annual revenues; and

(3) A description of how the filed rate differs in rate level or rate structure from the rate schedule currently effective.

(c) *Notice of filing*. The notice of filing, suitable for publication in the FEDERAL REGISTER, must contain the following information:

(1) The identification number or description of the rate schedule or contract;

(2) If the rate schedule includes changes in rates, the dollar amount and percent increase or decrease in rates;

(3) If the rate schedule includes changes other than rates, a brief description of the changes;

(4) A brief explanation of the reasons for any proposed change in the rate schedule;

(5) A statement whether interim approval of Bonneville Power Administration rates is requested;

(6) The proposed effective date of the rate schedule; and

(7) The proposed rate approval period.

(d) *Rate schedules.* A filed rate schedule, as defined in § 300.1(b)(7), must describe the following, as appropriate:

(1) The class of service to which each rate schedule will apply and service areas or zones which will be affected by the filed rate;

(2) The rate to be applied to capacity and energy services or other services;

(3) Special provisions, such as discounts, penalties, power factor adjustments, service interruptions, unauthorized overruns and other similar provisions which may affect the rate and charges; and

(4) The period during which the rates will be effective.

(e) *Statement of revenue and related costs.* Each filing shall include a statement which includes cost (if available) and revenue data for each class of service as specified in each rate schedule for the proposed period.

(f) *Explanation of rate development process and supporting documents.* (1) The Administrator must file the entire record on which the final decision establishing a rate scheduled is based.

(2) The Administrator must file a Record of Decision, if one is made, or an explanation of the rate development process, if a Record of Decision is not made. The Record of Decision or the explanation of the rate development process must include:

(i) A discussion of issues raised by customers or the public and how such issues were resolved;

(ii) A discussion of all statutory, regulatory, or other requirements which governed the Administrator's decision;

(iii) A description of any methodology used for determining revenue requirements and for developing appropriate rate structures;

(iv) A list identifying all documents submitted for Commission consideration; and

(g) *Certification.* The Administrator must file a statement certifying that the rate is consistent with applicable laws and that it is the lowest possible rate consistent with sound business principles.

(h) *Additional filing requirements.* (1) The Administrator must file with the Commission any other information relevant to the Commission's ratemaking decision.

(2) The Administrator must file any other information requested by the Office of Energy Market Regulation as needed for Commission analysis of the rate filing.

[Order 382, 49 FR 25235, June 20, 1984, as amended by Order 541, 57 FR 21734, May 22, 1992; Order 593, 62 FR 1284, Jan. 9, 1997; Order 647, 69 FR 32439, June 10, 2004; Order 699, 72 FR 45325, Aug. 14, 2007; Order 701, 72 FR 61054, Oct. 29, 2007; Order 714, 73 FR 57536, Oct. 3, 2008]

§ 300.11 Technical support for the rate schedule.

(a) *Filing requirement.* The Administrator must submit, in conjunction with any application under § 300.10, the technical support data described under paragraph (b) of this section and the analysis of data described under § 300.12 of this subpart.

(b) *Data*—(1) *Statement A—Sales and Revenues.* Statement A must include:

(i) Sales and revenues for each rate schedule for the last five years of the historic period, as defined in section 300.1(b)(3);

(ii) For the rate test period, the estimated annual sales and revenues for the existing and each proposed rate schedule, including a separate aggregation of any revenues from sources not covered by the rate schedule according to general classifications of such revenues; and

(iii) Brief explanations of how sales and revenue estimates are prepared and explanations of any changes in sales or revenues during the last five years of the historic period.

(2) *Statement B—Power Resources.* Statement B must contain a list of the capacity and energy resources for the last five years of the historic period and for the rate test period, used to support the sales and revenues figures contained in Statement A. The statement should identify resources according to the powerplant and any purchase or exchange agreement.

(3) *Statement C—Capitalized investments or costs.* (i) Statement C must account for all capitalized investments to be repaid from power revenues.

(ii) The statement shall include a listing, by year, of the following:

(A) All initial investments and additions to plant, including interest during construction, that produced revenue during the historic period or are expected to produce revenue during the rate test period;

(B) Capitalized deferred expenses; and

(C) Replacements made during the historic period and replacements projected to be made during the balance of the repayment period.

(iii) For each such investment, the statement shall specify:

(A) Whether the investment is an initial investment, an addition, a replacement, or a capitalized deferred annual expense;

(B) The date the investment was made;

(C) The year in which repayment is due to be completed;

(D) Whether the investment was financed through the issuance of revenue bonds, the appropriate interest rate, and the terms and conditions for such bonds; and

(E) The authority or administrative procedure used for the adoption of such interest rate.

(iv) If available, the amount repaid on each investment to date must be stated, except that if repayment on individual investments is not recorded, the amount repaid to date on each group of investments having common interest rates should be stated.

(v) For each year, the sum of unpaid individual investments or the unpaid portion of interest groups shown above must equal the unamortized investment shown in the power repayment study for that year.

(vi) The statement must describe the methods used to forecast replacements and the price level used to estimate replacement costs.

(4) *Statement D—Interest Expenses; Repayment of Investments and Debt Capital.* (i) For each capitalized investment and cost listed in Statement C, Statement D must describe, by interest group:

(A) The total unpaid balance outstanding at the end of the historic period;

(B) Payments made on principal and interest during each of the last five years of the historic period; and

(C) Annual payments expected to be made through the cost evaluation period.

(ii) The statement must describe how the interest expense was determined for each type of investment and include examples of such computations.

(5) *Statement E—Operation, Maintenance and Other Annual Expenses.* Statement E must contain, for the last five years of the historic period and for the rate test period, as appropriate, a tabulation of actual and projected operation and maintenance, administrative and general, purchased power, wheeling, and any other expenses, other than interest. Statement E must:

(i) List expenses for each individual source, if purchased power and other similar expenses are derived from more than one source;

(ii) Explain any significant deviations from trends in expenses or any extraordinary expenses; and

(iii) Explain the price level used for estimating expenses.

(6) *Statement F—Cost Allocations.* (i) Statement F must contain, for each multiple-purpose reservoir project, unit, division, or system, a table or other summary showing total investment costs, the total annual operation and maintenance costs, and the allocation of all such costs among the various authorized purposes.

(ii) The statement must show the amount of power costs suballocated to irrigation functions, any changes from previous allocations, and the procedure used in allocating such costs. Currently valid allocations previously submitted to the Commission need not be furnished, if referenced.

§300.12 Analysis of supporting data.

(a) An analysis of the data provided under §300.11 must be supported by an appropriate methodology developed by the Administrator.

(b) *Revenue recovery study.* (1) A study must be provided which supports the filed rate and charges, including a narrative statement that explains how the rates and charges meet the objective of recovering the revenue necessary to repay the Federal investment and other costs in a reasonable period of time.

(2) Any *Power Repayment Study* (PRS) submitted for this purpose must be developed using currently approved rates for estimating future revenues. If the filed rates differ from the current rates, the Administrator must provide a PRS which uses the level of revenues produced by the proposed rates. Unless otherwise required by statute, a PRS must contain only those investments in plant which will be in commercial operation during the proposed rate approval period, except replacements. Forecasts of costs beyond the rate test period must be based on conditions prevailing during the period, unless unusual circumstances warrant otherwise.

(3) A PRS must include, but need not be limited to, those items listed below:

(i) Operating revenues;

(ii) Operating expenses;

(iii) Interest expense;

(iv) Investment placed in service (using totals if the supporting statement annually shows a breakdown into the appropriate subcategories under each major heading), including the initial project, additions, replacements, and the total investment;

(v) Investment amortized;

(vi) Remaining unamortized investment;

(vii) Allowable unamortized investment (using totals if the supporting statement annually shows a breakdown into the appropriate subcategories under each major heading), including initial project, additions, replacements, and total investment;

(viii) Irrigation investment assigned to be repaid from power revenues (using totals if the supporting statement annually shows a breakdown into the appropriate subcategories under each major heading), including irrigation investment assigned to power, investment repaid, remaining unpaid investment, and allowable unpaid investment; and

(ix) Cumulative status of repayment.

(c) *Cost of service study.* For any project or system which provides more than one class of service for which differing rates are proposed, a cost of service study, if available, must be provided which shows how the costs of providing each service have been determined. If rates and charges have not been formulated on a cost related basis, the basis for each rate or charge should be explained.

§ 300.13 Waiver of filing requirements.

The Administrator must request waiver of any requirement of this subpart if an application that does not fully comply with that requirement is not to be considered deficient. The request must state the Administrator's reasons for such noncompliance and show good cause for any waiver.

§ 300.14 Filings under section 7(k).

Any application for Commission review and approval of a rate or rate schedules established by the Administrator of the Bonneville Power Administration pursuant to section 7(k) of the Pacific Northwest Electric Power Planning and Conservation Act must be filed in compliance with the provisions of §35.13(a)(2) of part 35 of this chapter and with the provisions of this part, and must include the classifications, practices, rules and regulations affecting the rate and charges and all contracts which in any manner affect or relate to such rate, charges, classifications, services, rules, regulations, or practices. However, such classifications, practices, rules, regulations or contracts which may affect or relate to rates will not be subject to Commission approval unless they are determined to be rates or rate schedules.

[Order 323–B, 52 FR 20709, June 3, 1987]

Subpart C—Commission Rate Review and Approval

§ 300.20 Interim acceptance and review of Bonneville Power Administration rates.

(a) *Opportunity to comment.* The Commission will publish in the FEDERAL REGISTER notice of any filing made under this part, for which interim approval is requested. This notice will give interested persons an opportunity to submit written comments on whether interim approval should be granted.

(b) *Action on request for interim rate acceptance*—1) *Deficient applications.* Upon receipt of an application that does not comply with the requirements of this part, the Commission may:

(i) Accept the application and order the rate schedule into effect on an interim basis, effective on the date requested by the Administrator or at such time as the Commission may otherwise order, on the condition that any deficiencies in the filing are corrected by the Administrator to the satisfaction of and within such time specified by the Director of the Office of Energy Market Regulation; or

(ii) Deny the Administrator's interim rate request and reject the application, if the Commission determines that the Administrator's application:

(A) Is patently deficient with respect to the filing requirements of this part; or

(B) Fails to comply with the applicable provisions of the Northwest Power Act or such other Acts as may be applicable.

(2) *Applications that are in compliance.* Upon receipt of an application that complies with the requirements of this part, the Commission may:

(i) Order the rate schedule into effect on an interim basis, effective on the date requested by the Administrator or at such time as the Commission may otherwise order; or

(ii) Deny the Administrator's interim rate request and review the application for final confirmation and approval of the rate schedule pursuant to the provisions of this part.

(c) *Condition of acceptance.* Any rate schedule the Commission allows to become effective on an interim basis under paragraph (b) of this section is subject to refund with interest.

(d) *Notice of action on interim approval.* The Commission will publish in the FEDERAL REGISTER a notice of any action taken under paragraph (b) of this section and will mail notice to any person on the Commission's service list.

[Order 382, 49 FR 25235, June 20, 1984, as amended by Order 699, 72 FR 45326, Aug. 14, 2007; Order 701, 72 FR 61054, Oct. 29, 2007]

§ 300.21 Final confirmation and approval.

(a) *Opportunity to comment and intervene.* (1) The Commission will publish notice in the FEDERAL REGISTER giving interested persons an opportunity:

(i) To submit initial and reply comments on any filing made under subpart B; and

(ii) To intervene in any proceeding held on such filing.

(2) With respect to the Bonneville Power Administration:

(i) Such notice will also give interested persons an opportunity to comment on whether it is necessary to hold a hearing on non-regional rates under section 7(k) of the Northwest Power Act and the issues to be resolved at such hearing.

(ii) This notice may be part of any Commission order granting interim approval under § 300.20 of this part.

(b) *Proceedings under section 7(k).* For the Bonneville Power Administration, the Commission will publish a separate order if it determines that a hearing is necessary under section 7(k) of the Northwest Power Act. This order will, if appropriate, delineate the issues to be resolved at such hearing. Such hearing will be held in accordance with the procedures established for ratemaking by the Commission pursuant to the Federal Power Act.

(c) *Standards of review for the Bonneville Power Administration*—(1) *Rates under section 7(a).* The Commission will review any rate established by the Administrator under section 7(a) of the Northwest Power Act for compliance with the following standards:

(i) The rates must be sufficient to ensure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs.

(ii) The rates must be based upon the Administrator's total system costs.

(iii) With respect to transmission rates, the rates must equitably allocate the costs of the Federal transmission system between Federal and non-federal power utilizing such system.

(2) *Rates under section 7(k).* The Commission will review any rate established by the Administrator under section 7(k) of the Pacific Northwest Electric Power Planning and Conservation Act for compliance with the requirements of the Bonneville Project Act, the Flood Control Act of 1944, and the

Federal Columbia River Transmission System Act.

(d) *Standards of review for other power marketing administrations.* The Commission will review the rates of the Alaska, Southeastern, Southwestern, and Western Area Power Marketing Administrations in accordance with the terms of any delegation made by the Secretary of Energy.

(e) *Action on request for final confirmation and approval of rates.* Filed rates will be considered for final confirmation and approval if the relevant filing complies with the filing requirements of subpart B of these regulations. The Commission may take any of the following actions:

(1) Confirm and approve the rate schedules for the period beginning with the date such rates where placed in effect on an interim basis or the effective date requested in the application to the expiration date requested in the application but not to exceed a five-year period, or for such lesser period, as the Commission deems appropriate;

(2) Remand the filing for further development of the record to support the filed rate schedules;

(3) Order an evidentiary hearing if there are questions of fact which can not be resolved from the record or through staff evaluation;

(4) Disapprove the filed rates; or

(5) Take such other action that the Commission considers appropriate.

(f) *Procedures upon disapproval.* If the Commission disapproves the rates, the Administrator will be provided a 120-day period, or other period as the Commission may deem appropriate, to prepare substitute rates that resolve the Commission's concerns. If the filed rates have been approved on an interim basis, the rates will continue in effect on an interim basis until the Commission takes final action.

(g) *Refund and interest*—(1) *Refund.* If a rate collected by any power marketing administration on an interim basis exceeds the rate which is confirmed and approved by the Commission as a final rate, the Administrator, pursuant to any conditions established by the Commission, must refund with interest any portion of the rate increase collected during the interim period which exceeds the final rate. The Administrator may make refunds by means of a net energy billing which reflects the value of any overcharge or other appropriate methods.

(2) *Interest.* Except as otherwise provided by the Commission, the Administrator must compute any amount of interest based on the revenues collected subject to refund and required to be refunded under this paragraph by using:

(i) With respect to the rates of the Bonneville Power Administration, the rate of interest or a weighted average of all rates of interest charged to the Bonneville Power Administration by the U.S. Treasury during the period for which the computation is made;

(ii) With respect to the rates of other Power Marketing Administrations, the rates of interest computed in accordance with the formula contained in DOE Order No. RA 6120.2, available from the Department of Energy (Office of Power Marketing Coordination) and the Power Marketing Administrations.

(h) *Notice of action on final approval.* The Commission's Secretary will publish in the FEDERAL REGISTER a notice of any action taken under paragraph (e) of this section and will mail the notice to the persons on the Commission's service list.

[Order 382, 49 FR 25235, June 20, 1984, as amended by Order 323–B, 52 FR 20709, June 3, 1987]

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

Sec.

AUTHORITY: 16 U.S.C. 839–839h.

SOURCE: Order 726, 74 FR 47059, Sept. 15, 2009, unless otherwise noted.

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

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

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

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

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

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

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

(A) The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three 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 (before additions) * [(NTP (before additions) + NTA)/NTP (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

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		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
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: (l)								
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		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
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					
Total Depreciation and Amortization Reserve					$ -	$ -	$ -	$ -
Total Net Plant *(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 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
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 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
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)*				

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)

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				

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 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
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					$ -	$ -	$ -	$ -

Schedule 3

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						$ -	$ -	$ -

Schedule 3

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)								

Schedule 3

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		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
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 Powe1	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

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.