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TESTIMONY of

RANDY B. RUSSELL, W. MICHAEL MCHUGH,

JULIA M. SHAUGHNESSY, and ROBERT E. YOUNG

Witnesses for Bonneville Power Administration

SUBJECT: AVERAGE SYSTEM COST AND LOAD FORECASTS FOR FY 2010-2015

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Randy B. Russell, and my qualifications are contained in WP-10-Q-BPA-55.

A. My name is W. Michael McHugh, and my qualifications are contained in WP-10-Q-BPA-44.

A. My name is Julia M. Shaughnessy, and my qualifications are contained in WP-10-Q-BPA-56.

A. My name is Robert E. Young, and my qualifications are contained in WP-10-Q-BPA-62.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the data sources, models, and assumptions we used to develop the FY 2010-2015 forecast of Average System Costs (ASCs) for utilities that may participate in the Residential Exchange Program (REP). This testimony sponsors Section 6 of the Wholesale Power Rate Development Study (WPRDS), WP-10-E-BPA-05; and Section 2.3.1 of the Section 7(b)(2) Rate Test Study (Study), WP-10-E-BPA-06, and supporting portions of the Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-10-E-BPA-06A.

Q. How is your testimony organized?

A. Our testimony is organized in five sections. Section 1 outlines the purpose of our testimony. Section 2 describes the Residential Exchange Program (REP), the 2008 ASC Methodology, and the purpose and function of the ASC Review Processes. Section 3 describes how the ASCs for FY 2010-2011 were determined. Section 4 describes the Residential and Small Farm Exchange Load forecasts for FY 2010-2015. Section 5 describes the process for determining the ASC forecasts for the remaining years of the 7(b)(2) rate test period (FY 2012-2015), including the data sources we used to calculate the ASC forecast for each participating utility.

Section 2: Residential Exchange Program and The 2008 ASC Methodology

Section 2.1: Description of the Residential Exchange Program

Q. What is the Residential Exchange Program?

A. The Residential Exchange Program was created by the Northwest Power Act to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the REP, BPA "purchases" power from each participating utility at that utility's Average System Cost of resources. BPA then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's Priority Firm Power (PF) Exchange rate. The amount of power purchased and sold is equal to the qualifying residential and small farm load of each utility participating in the REP. The Northwest Power Act requires that all of the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities.

Q. Does the REP involve a conventional purchase and sale of power?

A. Generally, no. Because the amounts of power purchased and sold are the same, the "exchange" is generally referred to as a "paper" transaction: BPA provides the participating utility cash payments that represent the value difference between power "purchased" by BPA and the less expensive power "sold" to the participating utility. However, the Northwest Power Act allows the REP to be implemented through actual sales of power if BPA elects to purchase from other sources in lieu of purchasing from the utility at its ASC.

Q. *Please explain when BPA would elect to purchase and sell actual power "in lieu" of purchasing at the utility's ASC.*

A. Under section 5(c)(5) of the Northwest Power Act, BPA

> … may acquire an equivalent amount of electric power from other sources to replace power sold to [a] utility as part of [the REP] if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

This acquisition of power from other sources is "in lieu" of the "purchase" from the utility that would otherwise occur under the REP. This purchase right is designed to provide a mechanism to limit the net costs of the REP. An in-lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable Residential Purchase and Sale Agreement (RPSA).

Q. *Are you assuming that BPA will make any "in lieu" transactions during this rate period?*

A. No, we are not. BPA's in-lieu policy is still under development at this time, so we do not have a framework to analyze if any "in-lieu" transactions will take place.

Section 2.2: Description of ASCs and the 2008 ASC Methodology

Q. *What is the Average System Cost of a utility?*

A. The ASC is the unit cost of a utility's allowable generation and transmission system as determined by the Administrator through an extensive review of the utility's cost and load data, ASC filings, supporting documentation, and reports. ASC (expressed in $/MWh) equals a utility's ASC Contract System Cost divided by its ASC Contract System Load. The review of the individual utility's ASC filing occurs in a separate administrative process that is not part of the WP-10 rate proceeding. Background information, publications, procedures and review schedules, participating utilities' data and ASC filings, and BPA's published reports will be available at http://www.bpa.gov/corporate/finance/ascm/.

Q. What is ASC Contract System Cost?

A. In general terms, ASC Contract System Cost is the exchanging utility's allowable generation and transmission costs (less the costs of serving any New Large Single Loads (NLSLs)) that serve its retail customers within the Pacific Northwest region. Contract System Cost includes an allocation of general plant and certain overhead costs. Costs associated with a utility's distribution function are generally excluded from Contract System Cost.

Q. What is ASC Contract System Load?

A. ASC Contract System Load is the exchanging utility's total regional retail loads, including distribution losses, less any NLSLs.

Q. How are ASC Contract System Cost and ASC Contract System Load determined?

A. ASC Contract System Cost and ASC Contract System Load are determined by following the prescribed functionalization rules and methodologies identified in the 2008 Average System Cost Methodology ("2008 ASCM").

Q. What is the 2008 ASCM?

A. The 2008 ASCM is an administrative rule developed by BPA in consultation with its customers and other stakeholders that sets out the procedures and the processes to determine a utility's ASC. The 2008 ASCM was developed in a separate public consultation process. The 2008 Average System Cost Methodology Final Record of Decision was signed by the Administrator on June 30, 2008, and received interim approval from the Federal Energy Regulatory Commission (the Commission) on September 30, 2008. *See* 2008 ASCM – www.BPA.gov/corporate/finance/ASCM. For ease of reference and for context, we have attached the 2008 ASCM to this testimony as Attachment A.

Q. How are ASCs determined under the 2008 ASCM?

A. Under the 2008 ASCM, ASCs are determined in an administrative process, known as an ASC Review Process. The ASC Review Process begins with the utility submitting an Appendix 1 filing, which is an electronic template that assigns all of the utility's financial data into exchangeable and non-exchangeable categories in accordance with the rules in the 2008 ASCM. Each exchanging utility also files an ASC Forecast Model, which projects certain components of the utility's data contained in the Appendix 1 filing to the midpoint of the BPA rate period. Once the Appendix 1 is filed, BPA commences a formal review process. During this process, BPA reviews the utility's data and checks the ASC for compliance with the ASCM. Other parties may intervene in these proceedings and request discovery, submit issue lists, and present oral argument, if granted, before the Administrator or the Administrator's designee. BPA issues a Draft ASC Report that calculates the utility's ASC and explains BPA's decision on any contested issues. Parties then have an opportunity to submit comments on the Draft ASC Reports. BPA then publishes the Final ASC Reports, which establish the utility's ASC for the rate period. For investor-owned utilities (IOUs), the ASCs must be filed with the Commission.

Q. Is BPA currently conducting any ASC Review Processes?

A. Yes. BPA is currently conducting ASC Review Processes to calculate utility ASCs for FY 2009 and FY 2010-2011.

Q. Are FY 2010-2011 rate period ASCs determined in this WP-10 rate proceeding?

A. No. Utility ASCs for FY 2010-2011 are determined in BPA's ASC Review Process, which is a completely separate administrative proceeding.

Q. Are forecasts of utility ASCs for FY 2012-2015 used in the 7(b)(2) rate test determined in this proceeding?

A. Yes, they are.

Section 3: Fy 2010-2011 Rate Period ASC Forecast

Q. How did you estimate a utility's rate period ASC for FY 2010-2011?

A. For the WP-10 Initial Proposal, we used the "as filed" ASCs submitted by utilities in the ASC Review Process in October of 2008. Because these filings are under review in the ASC Review Process, they are estimates of the final ASCs that will be determined by the end of the ASC Review Process. Issues related to the FY 2010-2011 ASCs are not within the scope of this proceeding. Therefore, we have limited our testimony to discussing general background information about the ASCs for context.

Q. Please explain in general terms how individual utilities' rate period ASCs for FY 2010 and FY 2011 were developed.

A. Each utility that participates in the REP program submitted an ASC filing for review. ASC filings for IOUs are based on the utility's 2007 FERC Form 1, and for consumer-owned utilities, their 2007 annual reports and audited financial statements. The filings include two Excel workbooks and numerous supporting documents and schedules. The Appendix 1 is an Excel workbook that develops a base period ASC for the year 2007. The ASC Forecast model is an Excel-based model that links to the Appendix 1 workbook and projects the 2007 base period ASC through FY 2010-2011, the WP-10 rate period.

Q. Did you make any adjustments to the "as filed" rate period ASCs?

A. Yes. We adjusted the "as filed" rate period ASCs to correct for known errors that BPA or the filing utility discovered after the ASC filings were submitted in the ASC Review Process. Additionally, we changed the market price of electricity, natural gas price escalation, inflation rates, and PF rates to be consistent with the values and assumptions used in the Initial Proposal.

Q. What errors did you correct for in the utilities' ASC filings?

A. BPA corrected the utilities' ASCs for any known errors in the utilities' ASC submittals. The corrections were as follows:

(1) For Avista, we added 1,423,334 MWh to the expected annual generation for its Lancaster plant, included as a new resource;

(2) For Franklin PUD, we assumed that Franklin's forecast load growth would be met with purchases from BPA at the PF rate rather than with market purchases;

(3) For Snohomish PUD, we made three changes. First, we changed the category of a new resource addition. The resource had been erroneously entered as a new purchased power contract, when in fact it was a hydro plant addition. Second, we revised a new resource addition on-line date to 10/1/2010 from 1/1/2011, the midpoint of the rate period, pursuant to the ASC Methodology. Third, we removed the costs and MWh of a major purchased power contract that is due to expire during the rate period.

Q. Will the rate period ASCs for FY 2010-2011 be revised for the Final Proposal?

A. Yes. We anticipate that the 2010-2011 ASC Review Process will be concluded prior to the Final Proposal. At that time, the Administrator or his designee will issue a Final ASC Report for each utility that submitted an ASC filing. Each Final ASC Report will contain a final base period ASC (FY 2007) and one or more final rate period ASC(s) for FY 2010-2011. For ratesetting purposes, for the Final Proposal we propose to replace the "as filed" ASCs with the final ASCs from the ASC Reports. Final reports for each utility will be published on BPA's Residential Exchange Program website, http://www.bpa.gov/corporate/finance/ascm/.

Q. When will the final reports be available?

A. The Final ASC Reports are scheduled to be released in July 2009.

Q. *Which utilities filed ASCs for FY 2010-2011?*

A. The following utilities filed ASCs for FY 2010-2011:

Avista Corporation

Franklin County PUD

Idaho Power Company (IPC)

NorthWestern Energy (NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Puget Sound Energy (PSE)

Snohomish County PUD (SNOPUD)

Section 4: FY 2010-2015 Forecast Of Residential and Small Farm Exchange Loads

Q. *What are the residential and small farm exchange loads?*

A. In general, a residential and small farm exchange load is defined as the sum of a utility's qualifying small farm and residential consumer loads, as determined by the terms of the utility's Residential Purchase and Sales Agreement.

Q. *How did you estimate the exchange loads for FY 2010-2015?*

A. Utilities intending to participate in the REP for FY 2010-2011 were required to submit with their ASC filings a forecast of their qualifying residential and small farm retail load, as measured at the retail meter, for FY 2010-2015. As stated in the testimony of Misley *et al.*, WP-10-E-BPA-11, the residential and small farm loads of each utility is evaluated for reasonableness and consistency with prior growth trends. Next, we adjusted each utility's residential and small farm retail load for distribution losses to arrive at the forecast of the "exchange" load.

Q. How did you forecast the distribution losses included in exchange loads for FY 2010-2015?

A. As part of their ASC Review Process submittals, the participating utilities provided distribution loss factors, along with the supporting documentation used to develop these factors. We applied these distribution loss factors to the residential and small farm retail load to calculate the distribution losses for the FY 2010-2015 period.

Q. How are the exchange loads for FY 2010-2015 used in ratesetting?

A. The residential and small farm exchange loads are used to forecast a utility's REP benefits by comparing the utility's ASC with BPA's PF Exchange rate, and then multiplying the difference by the utility's residential and small farm exchange load. The exchange loads for FY 2010-2015 are shown in the Documentation, WP-10-E-BPA-06, Appendix E, Table 4.

Q. Did you make any other changes or adjustments to the exchange loads for the FY 2010-2015 period?

A. No.

Section 5: FY 2012-2015 Forecast Of Average System Costs For the 7(B)(2) Rate Test Period

Q. Why are you forecasting ASCs for FY 2012-2015?

A. As discussed earlier, the 7(b)(2) rate test requires BPA to consider the "projected amounts to be charged" for the current rate period plus the "ensuing four years." To comply with this statutory requirement, ASCs for utilities participating in the REP for the rate period (FY 2010-2011) and the "ensuing four years" (FY 2012-2015) are necessary to estimate the costs of the REP. Through the ASC Review Processes, BPA will establish rate period ASCs for FY 2010-2011. This section of the testimony describes the estimate of utility ASCs for FY 2012-2015, the 7(b)(2) rate test period.

Q. How do you forecast the ASCs for FY 2012-2015?

A. To forecast ASCs for FY 2012-2015, we use a similar methodology as is being used to determine the ASCs for FY 2010-2011. We use the costs and loads in the rate period ASCs as the starting point. The rate period ASCs includes the cost of all new resources forecast to come on-line through the end of the rate period. Each line item in the FY 2010-2011 Contract System Cost forecast is linked to an escalator in the ASC Forecast Model. To calculate the ASCs for FY 2012-2015, we program the ASC Forecast Model so that it escalates the rate period ASC values forward through FY 2015. The model is set up to apply different escalation factors to the different cost and revenue categories that are used to calculate Contract System Cost.

Q. What escalators are used in the ASC Forecast Model?

A. The ASC Forecast Model uses the same escalators described in the 2008 ASCM. Briefly, these escalators include the following:

- Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses
- BPA's forecast of market prices for utility purchases to meet load growth and to estimate short-term and nonfirm power purchase costs and sales revenues
- BPA's forecast of natural gas prices
- BPA's estimates of the rates it will charge for its PF and other products

See Attachment A, 2008 ASCM. The escalation rates can be found in the Section 7(b)(2) Rate Test Study, Appendix E, Table 2. The forecast of market prices, from which the market price escalation rates are calculated, can be found in the Market Price Forecast Study Documentation, WP-10-E-BPA-03A, Table 18. The forecast of natural gas prices, from which the natural gas escalation rates are calculated, can be found in the Market Price Forecast Study Documentation, WP-10-E-BPA-03A, Table 16, line 61.

Q. *Why do you use the projected PF rates and prices from this proceeding for the various power products that BPA provides?*

A. The COUs can purchase power products from BPA that are not available to the IOUs. Therefore, we use projected future costs of products purchased from BPA during the rate period using BPA's forecast rates in the ASC Forecast Model.

Q. *When you develop each of the individual utility ASC forecasts, to what point do you escalate the underlying cost and revenue data?*

A. We escalate the costs and revenues for each utility to the midpoint of each fiscal year for FY 2012-2015.

Q. *How do you forecast the utilities' Contract System Loads for FY 2012-2015?*

A. As part of their ASC Review Process submittals, the participating utilities provided a forecast of their total regional retail load for FY 2012-2105. As noted in Misley, *et al.*, WP-10-E-BPA-11, these forecasts were assessed and determined to be reasonable. To each utility's total regional retail load, we added distribution losses and subtracted any NLSLs to arrive at the forecast of Contract System Load.

Q. *How do you forecast the distribution losses included in Contract System Loads for FY 2012-2015?*

A. As part of their ASC Review Process submittals, the participating utilities provided distribution loss factors, along with the supporting documentation used to develop these factors. We apply these same distribution loss factors to the total retail loads to calculate the distribution losses for the FY 2012-2015 period.

Q. *How do you forecast New Large Single Loads for FY 2012-2015?*

A. As part of their ASC Review Process submittals, the participating utilities include the MWh totals for all NLSLs they are serving. We are unaware of any additional NLSLs that will begin operations during the rate period or 7(b)(2) rate test period for any of the participating utilities. Therefore, we forecast no change in the number of NLSLs through FY 2015. In addition, we assume the NLSL load will not change for the entire period.

Q. How do you forecast the cost of the resources used to serve an NLSL for FY 2012-2015?

A. Endnote "d" of the 2008 ASCM outlines a specific methodology for calculating the resource costs used to serve an NLSL. *See* Attachment A. We use this methodology to calculate the resource costs of serving an NLSL for FY 2012-2015.

Q. How do you assume exchanging utilities would meet system load growth for FY 2012-2015?

A. With the exception of PacifiCorp, we assume any increase in system load would be met by short-term market purchases rather than new resource additions. The projected cost of meeting load growth is determined by multiplying the annual system load growth of each utility by the forecast of each utility's market price of energy.

Q. Why is PacifiCorp treated differently?

A. PacifiCorp is forecast to add a substantial number of new resources prior to the rate period, which results in an energy surplus. Under the 2008 ASCM, surplus energy is sold off-system at the short-term sales for resale rate. For PacifiCorp, system load growth is met by reducing the short-term system sales until the surplus is eliminated. Once the surplus is eliminated, the system load growth is met with short-term market purchases.

Q. How do you calculate purchased power expense and sales for resale revenue?

A. Purchased power expense and sales for resale revenue are calculated as follows:

1) Long-term and intermediate-term purchased power expenses and sales for resale revenues are escalated at the rate of inflation.

2) Short-term purchased power expenses are determined by multiplying the utility's short-term purchased power amounts (MWh) by the utility-specific forecast short-term purchased power price. Short-term purchased power MWh equal the net load of the utility not met from existing and new resource additions.

3) Short-term Sales for Resale revenues are determined by multiplying the utility's short-term sales for resale amounts (MWh) by the utility-specific forecast short-term sales for resale price. Short-term sales for resale equal the existing sales for resale plus any net surplus created by new resource additions.

Further details regarding the calculation of purchased power expense and sales for resale revenues can be found in the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Appendix G.

Q. Where are the forecast Contract System Cost, Contract System Load, and Average System Cost for the exchanging utilities for FY 2012-2015?

A. The forecasts for Contract System Cost, Contract System Load, and Average System Cost for FY 2012-2015 are shown in the Section 7(b)(2) Rate Test Study, Appendix E, Tables 1-3.

Q. Are there any adjustments that you plan to make to the ASC forecasts for FY 2012-2015 in the Final Proposal?

A. Yes. The FY 2012-2015 forecast of ASCs will be adjusted to reflect any changes that result from the final ASC Review Process determinations for the FY 2010-2011 rate period ASCs. In addition, we will update our ASC forecast using the Final Proposal natural gas price forecast, market price forecast, and PF rates.

Q. Does this conclude your testimony?

A. Yes.

DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

ATTACHMENT A TO THE FINAL RECORD OF DECISION OF THE 2008 AVERAGE SYSTEM COST METHODOLOGY

2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act

June 2008

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ATTACHMENT A
ASC METHODOLOGY

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AVERAGE SYSTEM COST METHODOLOGY
BONNEVILLE POWER ADMINISTRATION

The following rules set forth the procedures by which regional utilities will submit Average System Cost (ASC) filings to the Bonneville Power Administration (BPA) and by which BPA will review such filings. BPA's review shall determine a Utility's ASC for the purpose of participating in the Residential Exchange Program (REP) pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839c(c).

I. DEFINITIONS

A. **Appendix 1:** Appendix 1 is the electronic form on which a Utility reports its Contract System Costs and other necessary data to BPA for the calculation of the Utility's Base Period ASC.

B. **Average System Cost:** The rate charged by a Utility to BPA for the agency's purchase of power from the Utility under section 5(c) of the Northwest Power Act for each Exchange Period and is the quotient obtained by dividing Contract System Costs by Contract System Load.

C. **Base Period:** The calendar year of the most recent FERC Form 1 data.

D. **Base Period ASC:** The ASC determined in the Review Period using the Utility's Base Period data.

E**. Contract High Water Mark (CHWM):** The aMW 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 Contract High Water Mark Contract.

F. **Commission:** The Federal Energy Regulatory Commission.

G. **Contract System Costs:** The Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Under no circumstances shall Contract System Costs include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act.

H. **Contract System Load:** The total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology.

I. **Exchange Period:** The period during which a Utility's BPA-approved ASC is effective for the calculation of the Utility's REP benefits. The initial Exchange Period under this ASC Methodology is from October 1, 2008, through September 30, 2009. Subsequent Exchange

Periods shall be the period of time concurrent with the BPA rate period beginning October 1, or the effective date of BPA's rate period.

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

K. **Form 1:** The annual filing submitted to the Federal Energy Regulatory Commission required by 18 CFR §141.1.

L. **Jurisdiction:** The service territory of the Utility within which a particular Regulatory Body has authority to approve a Utility's retail rates. Jurisdictions must be within the Pacific Northwest region as defined in the Northwest Power Act.

M. **Labor Ratios:** The ratios which assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data shall be used based on the cost of service study used as the basis for retail rates at the time of review.

N. **New Large Single Load:** That load defined in section 3(13) of the Northwest Power Act and determined by BPA as specified in power sales contracts and Residential Sale and Purchase Agreements (RPSA) with its Regional Power Sales Customers.

O. **Public Purpose Charge:** Any charge based on a Utility's total retail sales in a Jurisdiction that is given to independent non-profit entities or agencies of state and local governments for the purpose of funding within the Utility's service territory: (i) conservation programs in lieu of utility conservation programs; and (ii) acquisition of renewable resources.

P**. Rate Period High Water Mark (RHWM).** The amount used to define each customer's eligibility to purchase power at a Tier 1 price 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 rate case.

Q. **Regional Power Sales Customer:** Any entity that can contract directly with BPA for the purchase of power under sections 5(b), 5(c), or 5(d) of the Northwest Power Act for delivery in the region as defined by section 3(14) of the Northwest Power Act.

R. **Residential Purchase and Sale Agreement (RPSA):** The power sales contract pursuant to section 5(c) of the Northwest Power Act between BPA and the Utility that defines and implements the power purchase and sale.

S. **Review Period:** The period of time during which a Utility's Appendix 1 is under review by BPA. The Review Period begins on June 1 and ends on or about November 15 of the fiscal year prior to the fiscal year BPA implements a change in wholesale power rates.

T. **Regulatory Body:** A state commission or consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

U. **Utility:** An investor-owned or consumer-owned (preference) Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

II. FILING PROCEDURES

The following procedures state the filing requirements for all Utilities that file an Appendix 1 to participate in the REP. Utilities must file an Appendix 1 with BPA to permit the calculation of each Utility's ASC.

A. <u>Initial Exchange Period (FY 2009) and Second Exchange Period (FY 2010-2011).</u>

1. A Utility's ASC for fiscal year FY 2009 shall be determined by BPA in accordance with this ASC Methodology and shall constitute the effective ASC for the REP effective October 1, 2008, unless (1) the Commission fails to approve this Methodology; (2) the Commission amends the Methodology in a manner that changes the Utility's ASC established by BPA; or (3) the Methodology is legally challenged and not affirmed on appeal by the United States Court of Appeals for the Ninth Circuit. The Base Period Appendix 1 filing will be from CY 2006.

2. The initial Exchange Period under this Methodology shall commence October 1, 2008, provided that the Commission has granted the Methodology interim or final approval by that date. The initial Exchange Period shall end on September 30, 2009.

3. Since the initial Exchange Period under this Methodology commences on October 1, 2008 and the Utility filings for FY2009 are also due that same day, BPA will pay the exchanging Utilities based on their October 1, 2008 filed ASC and then calculate a true-up to the final ASC after the BPA Review Period is concluded and BPA has issued the final ASC reports. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section *C. Failure to File an Appendix 1 and Patently Deficient Appendix 1*. Prior to the commencement of the BPA Review Process in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be trued-up during FY 2009.

4. For the Second Exchange Period, Utilities are required to submit their ASC filings by October 1, 2008 for FY 2010-2011. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section C. *Failure to File an Appendix 1 and Patently Deficient Appendix 1*. Prior to the commencement of the BPA Review Period in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be incorporated in BPA's FY 2010-2011 wholesale power rate case.

After BPA's Review Process is concluded, BPA will issue Utility ASC Reports to reflect the final Utility ASCs for the FY2010-2011 rate period.

B. Subsequent Exchange Period Filing Requirements

1. Subsequent Exchange Periods shall be equal to the term of subsequent BPA wholesale power rate periods. ASCs shall change during such Exchange Periods only for the reasons provided in this Methodology.

2. Except as provided for the initial and second Exchange Periods under this Methodology, Utilities shall electronically file at least one Appendix 1 with BPA by June 1 of each year. In years when BPA is not conducting a review process, these filings shall be for informational purposes only and shall not change a Utility's ASC. The Appendix 1 shall be accompanied by supporting documentation, studies and analysis used to prepare the Appendix 1. For investor-owned utilities, the Appendix 1 shall be based on the Utility's most recently filed Form 1 and limited information from prior FERC Form 1 filings as required. For consumer-owned utilities, the Appendix 1 shall be based on the Utility's most recent audited financial information and shall be accompanied by a cost of service analysis (COSA). Each Appendix 1 shall contain an attestation signed by a senior officer of the Utility stating that the filing has been compiled in accordance with the Commission's Uniform System of Accounts, this ASC Methodology, and Generally Accepted Accounting Principles and is consistent with applicable orders and policies of the Utility's Regulatory Body. See Appendix 2.

C. Failure to File an Appendix 1 and Patently Deficient Appendix 1

1. Failure to File an Appendix 1. If a Utility fails to timely file an Appendix 1 and refuses to cure the problem within the *Period to Cure* provided in step 3 below, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility failing to file an Appendix 1 will also allow BPA the discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

2. Filing a Patently Deficient Appendix 1. If a Utility files its initial Appendix 1 and it is patently deficient as determined by BPA and the period to cure, as outlined in paragraph 3 below, has expired, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility filing a patently deficient ASC filing will also allow BPA the discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

3. Period to Cure. If a Utility fails to timely file an Appendix 1, or if it files an ASC which BPA determines is patently deficient, BPA shall provide such Utility with written notice and a period of seven (7) calendar days within which to file, or re-file, as the case may be, a new or corrected Appendix 1. In the event the Utility fails to file or re-file, as specified above, by the end of the seven-day cure period, or if such re-filed Appendix 1, is likewise determined patently deficient, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility filing a patently deficient ASC filing will also allow BPA discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

D. Failure to File an Appendix 1 because of a New Residential Purchase and Sale Agreement

1. *New Residential Purchase and Sale Agreement.* After the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after the commencement of a Review Period or during the subsequent Exchange Period, then BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

E. Notice of Filing of Appendix 1

1. After a Utility files electronically an Appendix 1, BPA shall post the filings and non-confidential documentation on BPA's electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

2. BPA shall advise parties of the right to file a petition to intervene in BPA's ASC review process.

III. BPA REVIEW PROCESS

During a Review Period, the following procedures apply. These procedures shall not apply to informational ASC filings made outside of a Review Period.

A. BPA may petition to intervene in each retail rate proceeding for each Utility participating in the Residential Exchange Program. If BPA or any of its Regional Power Sales Customers has been denied the right to intervene in a retail rate review proceeding of a filing Utility when such intervention is for purposes of obtaining any information regarding costs or facts relevant to the determination of a Utility's ASC (after having made a good faith effort to intervene in such retail rate proceeding and having timely complied with applicable procedures to intervene in such retail rate proceeding), BPA may set that Utility's ASC equal to the PF Exchange Rate for the following Exchange Period. Exchanging Utilities must provide BPA and Regional Power Sales Customers with at least 60 days notice of their intent to change their retail rates.

B. Each Appendix 1 shall be reviewed by BPA or its designee and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the revised Appendix 1 complies with the requirements of this Methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each Appendix 1 shall be reviewed by BPA or its designee to determine whether the Contract System Load used by the Utility is an appropriate load for purposes of the Utility's ASC computation.

C. In calculating ASCs, BPA will make an independent determination of (1) the appropriateness of the inclusion of costs; (2) the reasonableness of the costs included in Contract System Costs; and (3) the appropriateness of Contract System Loads. BPA shall not be obligated to pay an ASC different than the ASC based on Contract System Costs and Contract System Load as determined by BPA; provided that if a final order of the Commission or a reviewing court rejects BPA's ASC determination, then the ASC payable by BPA shall be the ASC as revised by BPA on remand.

D. The Appendix 1 filing shall be subject to review as follows:

The BPA review process (not including the initial and second Exchange Periods) commences on June 1 (Day 1) of the Review Period (or such other date as may be established by BPA). BPA will review all Utilities' ASCs concurrently in a public process.

Note: The dates identified below and those listed on the Sample Timeline on pages 13-14 herein are generic and intended to illustrate a timeline that is representative of the ASC review process. Unless specified, the days listed represent calendar days. Each spring prior to the Review Period, BPA will post on its ASCM website (http://www.bpa.gov/corporate/finance/ascm/) or its successor, a detailed schedule, accommodating the applicable holidays and weekends, that shall be the official schedule for that Review Period.

1. Day 1: Utility filings due to BPA.

2. Day 3: BPA posts the Utility filings to its electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

3. Day 7: Deadline to file Utility specific petitions to intervene with BPA for the Review Process. Any Regional Power Sales Customer or state utility Regulatory Body who so requests will be accorded party status for BPA's ASC review process if said request is received by the established deadline. Other interested parties also may submit a petition to intervene and BPA shall grant party status at BPA's discretion. Petitions to intervene must state with particularity the petitioner's interest in the ASC review proceeding. Petitions to intervene must be filed for each respective BPA review proceeding in order for a party to comment on such individual proceedings. The filing Utility is automatically a party to its own ASC review proceeding. BPA will grant or deny petitions to intervene within seven days after the deadline for filing such petitions.

4. Day 10: BPA grants or denies petitions to intervene

5. Day 11-66: Parties allowed to submit Data Requests. BPA and parties shall electronically file data requests to the Utility and BPA. BPA will make data requests available to all parties. Each Utility shall respond to requests for information relevant to the Utility's Appendix 1 filing, provided that the furnishing of proprietary or confidential information to any party may be made

contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. The responses should be sent to the requestor and BPA.

For each data request, the responding Utility has 7 days to provide the requested data or object. If a Utility files an objection to a data request, the party submitting the data request has 4 days to respond to the objection. After the response to the objection is received or the 4 days to respond has elapsed, BPA then has 7 days to issue a ruling as to whether the Utility's objection will be sustained or overruled. If the objection is overruled, the Utility must provide the data requested within 7 days after the ruling. If a Utility does not provide requested data, BPA may, in its discretion, remove from Contract System Costs all costs associated with the data not provided.

6. Day TBD: BPA will commence workshops on all Appendix 1 filings based on the specific schedules. Utilities filing Appendix 1s shall have staff or agents available for questioning by BPA and other parties to the proceeding. The primary purpose of the first workshop is to clarify data, work papers, supporting documentation and assumptions used to prepare the Appendix 1.

7. Day 88: By this day, BPA and parties may electronically file with BPA an issues list identifying contested elements of a Utility's ASC filing and the basis for the party's issues. BPA will make the issues lists available to all parties.

8. Day 102: By this day, each filing Utility will electronically file a response to issues lists. BPA and other parties also may file comments in response to issue lists.

9. Day 108: By this day, a workshop will be held to discuss and resolve issues raised by parties through their issues lists.

10. Day 111: Requests for oral argument before the Administrator or his/her designee must be submitted in writing to BPA by this day. Such requests shall contain a statement setting forth reasons why the party believes oral argument is necessary.

11. Day 114: BPA, at its discretion, may grant or deny any request for oral argument by this day.

12. Day 123: In the event a request for oral argument is granted, the requesting party shall present its argument first. Responding parties shall present their arguments thereafter. The Administrator or his/her designee, at his discretion, may provide an opportunity for the requesting party to reply. Oral argument shall be presented no later than this day.

13. Day 141: By this day, BPA will publish for comment and electronically serve Draft Utility ASC Reports on all parties. The Reports will contain analyses and decisions on all contested issues raised in the ASC review process.

14. Day 154: By this day, the Utility and parties may file comments on the Draft Utility ASC Reports.

15. Day 167: The BPA Administrator will issue Final Utility ASC Reports.

16. If BPA has not issued the Final Utility ASC Reports by the end of the Review Period, the ASC filed by the Utility shall be the Exchange Period ASC until the date BPA issues the Final Utility ASC Reports. The final ASCs determined by BPA shall then be the Exchange Period ASCs, effective back to the beginning of the Exchange period and until the end of the Exchange Period.

IV. RULES FOR DETERMINING EXCHANGE PERIOD AVERAGE SYSTEM COST

A. Escalation to Exchange Period

1. BPA will escalate BPA approved Base Period costs to the midpoint of the fiscal year for a 1-year rate period/Exchange Period, and to the midpoint of the 2-year period for a 2-year rate period/Exchange Period to calculate Exchange Period ASCs.

2. For purposes of the escalation referenced in paragraph 1 above, BPA will use Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. The following list of acronyms defines Global Insight's escalation codes, with exception of the natural gas escalator which is provided by BPA.

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

TOPS	Transmission Operations
WAGES	Wages

Table 1 in section VIII shows the escalators to be used for each line item included in the Appendix 1.

3. If any of the escalators specified in the ASCM are no longer available, BPA will designate a replacement source of escalators that, as near as possible, replicates the results produced by the prior escalator and, if such a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator.

4. BPA will base the costs of power products purchased from BPA on BPA's forecast of prices for its products.

B. Treatment of Sales for Resale and Power Purchases

1. BPA will escalate long–term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.

2. BPA will not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period will be used as the starting values. A Utility will then be allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASC.

3. BPA will use the method as described below to determine separate market prices to forecast short-term purchased power expense 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 mid-point between the Utility's average short term purchased power price and short term sales for resale price will be calculated for each of the years in 1.

c. The percentage spread around the Utility's mid-point between the average short term purchase power price and short term sales for resale price will be calculated for each of the years in 1.

d. A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will then be calculated. The following weighting scale will be used:

    i. 3 times Base Period spread

ii. 2 times (Base Period year minus 1) spread
iii. 1 times (Base Period year minus 2) spread

e. The Base Period mid-point price calculated in 2 will be escalated at the same rate as BPA's market price forecast.

f. The weighted average spread calculated in 4 will then be applied to the forecasted mid-point calculated in 5 to determine the purchased power and sales for resale price, to value purchased power expenses and sales for resale revenue to be included in Rate Period ASCs.

g. This same method will be used to calculate the market price forecast for short-term purchased power expense and sales for resale revenues for use in the load growth not met by new resource additions.

C. Major Resource Additions and Materiality Thresholds

During the Exchange Period, BPA will allow changes to a Utility's ASC to account for major new purchase power contracts or major new resource additions that come on-line and are used to meet the Utility's retail load. These changes, however, have to meet a materiality threshold in order for BPA to allow an ASC to change. These ASCs will be determined by BPA during the Review Period. The changes to the ASC will become effective when the resource begins commercial operation or power is received under the purchase power contract. Such criteria will also apply to resources that are sold, transferred or retired.

BPA will use the following method to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold. These additions will include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

1. BPA will apply a materiality threshold of a 2.5 percent change in a Utility's Base Period ASC for determining when a change in ASC will be allowed for resource additions or reductions. BPA will allow a Utility to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. This treatment allows an exchanging Utility to include resources required under state renewable resource mandates while lessening the administrative cost and burden of verifying the resource cost estimates during the ASC Review Period.

2. At the time the Utility submits its Appendix 1 filing, the exchanging Utility will provide its forecast of major new resource addition and all associated costs. The forecast will cover the period from the end of the Base Period to the end of the Exchange Period.

3. BPA will calculate new transmission wheeling revenues associated with new transmission investment by the following formula:

$$NTWR = WR_{(before\ additions)} * [(NTP_{(before\ additions)} + NTA) / NTP_{(before\ additions)}]$$

Where:

- $NTWR$ = New transmission wheeling revenues
- $WR_{(before\ additions)}$ = wheeling revenues (before additions)
- $NTP_{(before\ additions)}$ = (Net Transmission Plant (before additions)
- NTA = new transmission additions

4. The forecast of the major new resource costs to be included in the Utility's Exchange Period ASC will be reviewed and determined during the Review Period.

5. All major new resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the mid-point of the Exchange Period.

6. For each major new resource addition forecast to be available to meet regional retail load during the Exchange Period, BPA will calculate the difference in ASC between the ASC without the new resource and the ASC with the new resource (the ASC delta) at the mid-point of the Exchange Period.

7. When the resource comes on-line, BPA will add the ASC delta to the Utility's then current ASC to determine its new ASC.

8. Steps 1 through 7 above will also be used in a similar manner for resources that are sold, transferred or retired.

9. BPA will escalate the Base Period average per-MWh cost of Distribution Plant forward to the mid-point of the Exchange Period, and use the escalated average cost to determine the distribution-related cost of meeting load growth since the Base Period. This cost will be included in the Exchange Period ASC.

10. BPA will issue special procedural rules to ensure the confidentiality of information provided by Utilities regarding any new major resource additions as part of its Review Process. BPA 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 ASC. However, as is the case for other Utilities that do not have major resource additions in a particular year, load growth will be assumed to be met with purchases on the wholesale market, as described in section IV.E. of this Methodology. What the Utility loses by not supplying confidential resource data is the difference between the cost of the resource and the price of electricity in the wholesale market.

D. Forecasted Contract System 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 study as described in endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load will start with the Base Period and extend through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load will be provided on a monthly basis for the Exchange Period.

E. Load Growth Not Met by New Resource Additions

All forecast load growth not met by new 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 market purchases priced at the Utility's forecast short-term purchased power price unless the Utility has forecasted major resource additions.

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

3. In the event that the power provided by a new resource exceeds the Utility's forecast load growth, the excess will be sold as surplus power into the market and priced at the Utility's forecast sales for resale price as determined by BPA in section IV.B.

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 service territory, and the resulting change in ASC falls within the 2.5% or greater materiality threshold, the Utility will submit two ASC filings:

1. A Base Period ASC that does not reflect the acquisition or loss of service territory, and

2. A second filing that incorporates:

a. The forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

b. The forecast of the increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.

c. In addition to including the forecast of capital and operating cost increases or reductions associated with the change in service territory, the Utility must also forecast the changes in purchased power expense, sales-for-resale credit and other costs based on the changes in the service territory

d. 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, BPA will not adjust the Utility's ASC until the change in service territory takes place.

G. ASC Determination for COUs that elect to execute Regional Dialogue HWM Contracts

BPA will utilize the following approach:

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

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

3. During the Average System Costs Review process the Utility shall submit the data necessary to determine the fully allocated unit cost of resources in excess of the resource amounts used to calculate its CHWM.

4. Calculate the Utility's Total Unadjusted Contract System Cost (CSC) as described in the ASCM

5. Calculate a load growth credit {(Current System Load minus RHWM system Load) * Unit costs from 3 above}.

6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit (from 5 above).

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

H. Timely filing of Appendix 1

Utilities must file ASC information by June 1 each year, as required in section II, for BPA'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 section F above.

V. CHANGE IN AVERAGE SYSTEM COST METHODOLOGY

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 BPA's preference customers, or from three-quarters of BPA's direct-service industrial customers may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, the Administrator may file a new ASC Methodology with the Commission. However, the Administrator shall not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, *viz;* one year after the then-existing Methodology has been adopted by BPA and approved by the Commission through interim or final approval, whichever occurs first.

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 section 5(c)(7)(A)-(C) of the Northwest Power Act or to conform to the Federal Energy Regulatory Commission's revisions to the Uniform System of Accounts.

VI. SAMPLE TIMELINE REVIEW PROCEDURES

Note: BPA's ASC review process of Utilities' Appendix 1s occurs only in the year before BPA establishes new Wholesale Power Rate Schedules. However, Utilities are required to file an Appendix 1 by June 1 of each year in order that BPA can maintain current data.

The schedule below is a generic schedule that is representative of the timeline for the ASC review process. Each spring in the year prior to BPA implementing new Wholesale Power Rates, BPA will post a detailed schedule incorporating the applicable holidays and weekends.

DAY[1]	**EVENT**
June1	Utilities file electronic Appendix 1s with BPA.
June 7	Deadline to file petitions to intervene with BPA.
June 10	BPA grants or denies petitions to intervene.
June 11	Begin Data Request period.
TBD	Workshop(s) on Utilities' Appendix 1 filings.
Aug 22	End Data Response period.
Aug 27	Deadline for BPA and parties' issue lists on Utilities' filings.
Sept 10	Deadline for reply issue lists from all parties on Utilities' filings.
Sept 16	Workshop to discuss issue lists on Utilities' filings.
Sept 19	Deadline to request oral argument.
Sept 22	BPA grants or denies requests for oral argument.
Oct 1	Oral argument (if granted).
Oct 19	BPA publishes Draft ASC Report.
Nov 1	Deadline for Utilities' and parties' comments on Draft ASC Report.
Nov 14	BPA Administrator issues Final ASC Report.

[1] Deadlines end at 5 p.m., Pacific Prevailing Time, of the due date.

VII. APPENDIX 1 INSTRUCTIONS

Appendix 1 is the form on which a Utility reports its Contract System Costs, Contract System Loads, and other necessary data for the calculation of ASC. Appendix 1 is an electronic template consisting of seven schedules and several supporting files that must be completed by the Utility in accordance with these instructions and the provisions of the Endnotes following the schedules.

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. The ASC Filing Attestation Statement is presented at Appendix 2. The primary source of data for the investor-owned utilities' Appendix 1 filings is the Utility's prior year FERC Form No. 1 (Form 1) filing. Any items not applicable to the Utility shall be so identified. For consumer-owned utilities that do not follow the Commission Accounts, filings must include reconciliation between Utility Accounts and the items allowed as Contract System Costs. In addition, the COSA must be reviewed by an independent accounting or consulting firm. The COSA report must be accompanied by a report from an independent accounting firm or a consulting firm that outlines the review work that was performed in preparing the COSA report along with an assurance statement that the information contained in the COSA report is presented fairly in all material respects. The COSA report statement is presented in Appendix 2, Exhibit A, Statement of Review and Compilation of Work Performed. An outline of the financial documents that accompany an ASC filing for both investor-owned utilities and consumer-owned utilities is presented in Appendix 2, Exhibit B.

The primary schedules are as follows. The ASC Appendix 1 template is available electronically at http://www.bpa.gov/corporate/finance/ascm/, or its successor site.

Schedule 1: Plant Investment/Rate Base
Schedule 1A: Cash Working Capital
Schedule 2: Capital Structure and Rate of Return
Schedule 3: Expenses
Schedule 3A: Taxes
Schedule 3B: Other Included Items
Schedule 4: Average System Cost

The filing Utility shall reference and attach work papers, documentation and other required information that supports costs and loads, including details of allocation and functionalization. All references to the Commission Accounts are to the Commission's Uniform System of Accounts as of July 1, 2006 or as amended by subsequent Commission actions. The costs includable in the attached schedules are those includable by reason of the definitions in the Commission Accounts. If the Commission Accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent BPA determines that a particular change results in a change in the type of costs allowable for REP purposes. In such event, BPA shall address the changes, including escalation rules, in its Review Process for the following Exchange Period.

BPA 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.

A Utility operating in more than one Pacific Northwest Jurisdiction shall file one Appendix 1.

A Utility operating in Jurisdictions outside the Pacific Northwest shall 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. Such Utility's Appendix 1 filing shall include details of the allocation.

This allocation shall exclude all costs of additional resources used to meet loads outside the region, as required by section 5(c)(7) of the Northwest Power Act. All schedule entries and supporting data shall be in accord with Generally Accepted Accounting Principles and practices as these principles and practices apply to the electric utility industry.

A Utility shall file an Attestation Statement with each Appendix 1 filing and supporting documentation for each Review Period. See Appendix 2.

VIII. AVERAGE SYSTEM COST METHODOLOGY FUNCTIONALIZATION

Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. 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 below.

The following chart identifies the functionalization codes:

DIRECT	Direct Analysis
PROD	Production
TRANS	Transmission
DIST	Distribution/Other
PTD	Production, Transmission, Distribution/Other Ratio
TD	Transmission, Distribution/Other Ratio
GP	General Plant Ratio
GPM	General Plant Maintenance Ratio
PTDG	Production, Transmission, Distribution/Other, General Plant Ratio
LABOR	Labor Ratio

A. <u>Functionalization Rules</u>:

1. Functionalization of certain Accounts may be based on Direct Analysis or with a default ratio associated with that specific Account as shown on Table 1. Once a Utility uses a specific functionalization method for an Account, the Utility may not change the functionalization for that Account without prior written approval from BPA.

2. The Utility must submit with its Appendix 1 any and all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation could result in the entire Account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

B. Functionalization Methods:

1. Direct Analysis, if allowed or required by Table 1, assigns costs to the production, transmission, and/or distribution function of the Utility. The only exception to this requirement is for conservation-related costs. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. Such analysis is subject to BPA review and approval. Once a Utility uses a specific functionalization method for an Account, the Utility may not change the functionalization for that Account without prior written approval from BPA.

2. BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio.

3. Utilities that wish to include advertising and promotion costs related to conservation will do so with a Direct Analysis. If a Utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. The presence of conservation-related costs in an Account does not give the Utility permission to perform a Direct Analysis on the entire Account. This option allows a Utility to assign costs in the specified Account to Production, Transmission and/or Distribution/Other based on analysis and support from the Utility that demonstrate such cost assignment is appropriate. The Utility must submit with its ASC filing any and all work papers, documents, and other materials that demonstrate the functionalization contained in its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such 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 shall be functionalized to Production as appropriate.

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	PTD	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	
Leasehold Improvements	108	DIRECT	DIST	CONSTANT
In-Service: Depreciation of Common Plant	108	DIRECT	PTD	CONSTANT
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT
Amortization of Acquisition Adjustments	115	DIRECT	DIST	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

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**	
Deferred Losses from Disposition of Utility Plant	187	DIRECT	N/A	CONSTANT
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 (Excluding REP Reversal)	555	PROD		CONSTANT
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		CONSTANT
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	DIRECT	N/A	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	DIRECT	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
Other Production Plant	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**	
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	447	PROD		CONSTANT
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
Labor Ratios				
Labor Ratio Input:				
Production		PROD		WAGES

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	
Transmission		TRANS		WAGES
Distribution		DIST		WAGES
Customer Accounts		DIST		WAGES
Customer Service and Informational		DIST		WAGES
Sales		DIST		WAGES
Administrative & General		PTD		WAGES

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Appendix 1
ASC Utility Filing Template

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

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

Schedule 1: Plant Investment / Rate Base

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

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

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

Schedule 1: Plant Investment / Rate Base

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

(Total Electric Plant In-Service) - (Total Depreciation & Amortization)

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Appendix 1

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

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				0	-	-	-
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST			-	-	-
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					$ -	$ -	$ -	$ -
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD			-	-	-
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

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			-	-	-
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					**$ -**	**$ -**	**$ -**	**$ -**
Total Assets and Other Debits					**$ -**	**$ -**	**$ -**	**$ -**

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Appendix 1

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

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 Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST		-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ -	$ -	$ -	$ -

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
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	$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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						

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

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

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

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) **35%**

Federal Income Tax Factor

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

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

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

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

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

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

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

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

Step 2: Calculate Return on Rate Base

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

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
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		0	-	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					$ -	$ -	$ -	$ -
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS			-	-	-
Total Maintenance	320-323	568-574	TRANS			-	-	-
Total Transmission Expense					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
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
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	DIRECT					
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 (g)	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 (g)	320-323	930.1	DIST	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					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Schedule 3: Expenses

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

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
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 Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
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		$ -	-	$ -	-	$ -	-

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Schedule 3A Items: Taxes

Account Description	FERC Form 1		Funct. Method	Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers					
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, etc.	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				$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Schedule 3B Other Included Items (j)

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 Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD			-	-	-
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD		-	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ -	$ -	$ -	$ -
Total Other Included Items					$ -	$ -	$ -	$ -

(Total Other + Total Sales for Resale + Total Other Revenue)

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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)*	**$ -**	**$ -**	**$ -**	**$ -**

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

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	$ -
(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 Loss (e)	0
Total Contract System Load	**0**
Average System Cost $/MWh	**$0**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
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**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
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%**

GP **General Plant Ratio**	Ratio Used	Total	Production	Transmission	Distribution
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		$ -	$ -	$ -	$ -
GP RATIO		**0%**	**0%**	**0%**	**0%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Ratio Table

PTD	Production, Transmission, Distribution Ratio	Ratio Used	Total	Production	Transmission	Distribution
	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%**

PTDG	Production, Transmission, Distribution and General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	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%**

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

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Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

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

Ratio Table

GPM	Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	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%**

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

a/ Contract System Costs shall 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 shall 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 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 shall 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 shall 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 BPA'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 BPA transmission charges if transmission costs are excluded in the determination of BPA's NR rate, to the extent such 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 such excess load shall be determined by multiplying the kilowatt-hours not served under subsections (1) and (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 BPA, 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 shall be priced at the average cost of transmission during the Exchange Period.

The above three paragraphs shall determine the Base Period cost of resources used to serve NLSLs. BPA 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 shall be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss can be measured using one of the following 3 methods:

Method 1, Distribution Loss Study: Losses shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load. Distribution losses shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

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

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

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

ii. From this 5-year total system loss factor, subtract the loss factor for BPA's 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 Form 1, but a 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, BPA 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 which 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 Council's resource plan as determined by the 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 ASCM 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. BPA 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 FERC's seven factor test contained in Order 888, and its 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 Form 1 filing. However, if a Utility is not required to file a 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 FERC'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.

Appendix 2
Chief Financial Officer Attestation

Exhibit A:
Statement of Review and Compilation of Work Performed

Exhibit B:
Financial Reporting Process and Attestation for IOUs and COUs

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Appendix 2
Chief Financial Officer Attestation

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

I, ____, having reviewed the Average System Cost (ASC) Appendix 1 Filing (ASC Filing) attached with this attestation, and in accordance with Exhibit A, *Statement of Review and Compilation of Work Performed*, of this Appendix 2, hereby certify that:

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

2. The ASC Filing excludes the costs associated with: (a) the cost of additional resources in an amount sufficient to serve any New Large Single Load after September 1, 1979; (b) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (c) any costs of any generating facility which is terminated prior to initial commercial operation.

3. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing is based on <<Customer's Name>>'s audited financial statements, FERC Form 1 filings and/or Cost of Service Analysis (COSA), and other financial information, and fairly presents in all material respects the operating costs of the utility for ___________, 20XX through ___________, 20XX.

4. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Chief Financial Officer
<<Customer's Name>>

Date:_____________________

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Exhibit A to Appendix 2
Statement of Review and Compilation of Work Performed

<<Customer's Name>>
Cost of Service Analysis Report
for the Base Period _______________, 20XX
through _______________, 20XX

This document is intended to be used by Engineering and Consulting Firms to provide; 1) a statement of the review work that was performed to ensure the accuracy and correctness of the information contained in the COSA report, and 2) to provide an assurance statement that the information contained in the COSA report is presented fairly in all material respects. Independent accounting firms would present similar information in their COSA compilation reports. The Appendix 1 references below simply denote where the financial and load data will ultimately appear in the Appendix 1 filing.

Section 1 – Statement of the Work performed and procedures that were followed in preparing the Cost of Service Analysis (COSA).

Examples of work performed cited in the Statement of Work should include:

1. Reconciliation of (1) results of financial statement expense information with (2) data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3).
2. Reconciliation of (1) tax expense and amounts paid in-lieu of taxes to state and local governmental bodies per the financial statement expense information with (2) the tax expense information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3A).
3. Reconciliation of (1) revenue credits and other included items used to reduce the rates of the utility's native load customers contained in financial statement income information with (2) the information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3B).
4. Reconciliation of (1) cash and short-term investment financial statement account information with (2) working capital data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 1A).
5. Plant investment costs, accumulated depreciation on plant investments and net un-depreciated plant investment at year end date is reconciled to the plant investment information contained in the COSA report. Plant investment costs associated with New Large Single Loads; generating assets used to serve loads outside of the Pacific Northwest region; and generating facilities that were terminated prior to commercial operation should be identified in separate accounts (ASC Filing, Appendix 1 - Schedule 1).
6. Long-term debt information (date bonds issued, original issue amount, principal balance at year end date, and interest rate of each bond issued along with a

weighted average cost of long-term debt outstanding) is reconciled to the information contained in the COSA report (ASC Filing, Appendix 1 – Sch. 2).

7. Return on plant investment calculation (net plant investment per Item 3 above times the weighted average cost of long-term debt per Item 4 above) is reconciled to the information contained in the COSA report.
8. Items 1-3 and 5-7 above are aggregated to produce the total cost of service amounts (aggregate costs have to be less than the projected costs contained in the utility’s rates) and divided by annual customer loads (Item 9 below) to arrive at the utility’s base period ASC.
9. Annual customer load information (annual megawatt hours) per the statistical section of the annual report is reconciled to the COSA report information.
10. Description of analytical procedures performed to gain additional assurance over the COSA report information. Comparison of current year information with prior year information, trend analysis, financial ratio analysis, and comparison of customer load information by segment with prior year load information.
11. Description of additional compilation and review procedures performed in preparing the COSA information.

<u>Section 2 – Report Assurance</u>

Based upon the audited financial statements of <<Customer’s Name>> for the year ending ______________, 20XX, along with other financial statement and utility operating information provided to us, we have reviewed <<Customer’s Name>>’s COSA report for the twelve month period ending __________. Our review included sufficient compilation review procedures along with additional analytical procedures to allow us to conclude that the information contained in the COSA report is presented fairly in all material respects.

Respectfully submitted,

_____________________________, <<Title>>
<<Company Name>> Auditing, Engineering or Management Consulting Firm

Date:___________________

Exhibit B to Appendix 2
Financial Documentation Requirements and Attestations for IOUs and COUs