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ADMINISTRATOR'S
RECORD OF DECISION
AVERAGE SYSTEM COST METHODOLOGY

PREPARED BY

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

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Administrators Record of Decision

Average System Cost Methodology

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I. Introduction.

The Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) authorizes an exchange of power between the Bonneville Power Administration (BPA) and Pacific Northwest electric utilities for the purpose of serving the utilities residential and usual farm loads (residential loads). A utility that enters into the exchange will sell power to BPA at the average system cost (ASC) of its resources. BPA then must sell an equivalent amount of power back to the exchanging utility at the rate BPA charges its preference utility customers. The cost benefits of this exchange must be passed through to the utilities' residential customers. The Regional Act provides that the amount of power to be exchanged will be 60 percent of residential load for the year beginning July 1, 1981, and will increase annually by equal increments until it reaches 100 percent on July 1, 1985. It is anticipated that substantial cost benefits will be passed through to the participating utilities' residential customers because BPA's wholesale firm power rate is less than the prospective ASC of some Pacific Northwest utilities. Therefore, the exchange will make it possible for all the region's utilities to have comparable wholesale power costs for the region's residential consumers.

The residential exchange is an element in the system established by the Regional Act for serving loads and recovering costs. Preference customers and the loads of the electric utilities under the exchange are served from the Federal base system resources and any additional resources necessary to meet these loads. Costs associated with these resources will be recovered from these customers. The direct-service industries (DSIs) will pay rates prior to July 1, 1985, sufficient to recover the costs of resources required to serve their load, plus the net costs incurred by BPA for the exchange. After July 1, 1985, the DSIs' rates will be based on the rate preference customers pay for BPA power, plus the typical margin charged to the preference customers' industrial consumers, with further adjustments for reserves provide and other items. In return for these higher rates, the Regional Act provides that BPA will offer the DSIs' new long-term contracts to serve their power needs. Therefore, prior to 1985 the net cost of the exchange will be borne primarily or solely by the DSIs. After 1985, the exchange costs may affect the rates to all rate classes.

The Regional Act requires that the BPA Administrator develop a methodology for determining the ASC for electric power exchanged. Further, the methodology must be developed in consultation with the Pacific Northwest Electric Power Planning and Conservation Council, BPA's customers, and appropriate State regulatory bodies in the region. The methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC).

This document has been prepared to trace the decisionmaking process that I, as Administrator of BPA, employed in overseeing development of the attached ASC methodology. The attached exhibit will be submitted to FERC for review and approval. In addition, the methodology will be Exhibit C to the Residential Purchase and Sale Agreements between BPA and the region's participating utilities that will be offered by BPA before September 5, 1981, as required by the Regional Act.

The methodology was developed in consultation with interested parties through a series of working group meetings attended by representatives of investor-owned utilities (IOUs), publicly owned utilities, direct-service industries, the regions State regulatory agencies, members of the public, and BPA staff. The process began in February 1981 and continued to mid-June, when the initial proposed methodology was published. The goal of the consultation process was to develop an administratively feasible ASC methodology that would achieve the intent of the Regional Act and produce results which are equitable and technically sound.

The participants in the consultation process represented groups with diverse interests. Each of the major groups will be impacted differently by the ASC methodology. Numerous complex financial, legal, and operating matters are involved in the process of determining utility costs. Consequently, many alternative techniques for determining ASC were identified and discussed. The consultation process did not result in a consensus on all ASC matters. However, a consensus among the participating parties was reached on the basic procedures to be used in the ASC methodology, as well as on numerous specific features of the methodology. Matters agreed upon for the initial proposed methodology include the jurisdictional costing approach, many cost functionalization procedures, determination of distribution losses, treatment of in-lieu taxes for public utilities, and the scope of BPA's review of each utility's ASC filings.

In light of the Regional Act requirement for a consultation process and the limited time available before October 1, 1981, the earliest date sales can be made, BPA chose, consistent with BPA's "Procedure for Public Participation in Major Regional Power Policy Formulation" (46 FR 26368 May 12, 1981), to combine the Notices of Intent and Proposed Policy. This decision was made because the consultation process substantially duplicated the Notice of Intent process by providing for recommendations from interested parties. The "Notice of Proposed Average System Cost Methodology and Opportunities for Public Review and Comment" was published in the FEDERAL REGISTER on June 23, 1981, (46 FR 32727) and the comment period closed July 24, 1981. Written comments were received from investor-owned and public utilities, BPA's direct-service industry customers, two State utility commissions, and individuals.

A public comment forum concerning the proposed ASC methodology was held on July 8, 1981, at BPA headquarters, Portland, Oregon. At the opening of the hearing BPA presented an overview of the ASC methodology, including relevant portions of the Regional Act, a summary of the consultation process, and the ASC schedules and procedures. Following this presentation members of the public were encouraged to ask clarifying questions and to present statements of their concerns. The hearing was transcribed and the transcript was reviewed in arriving at the decision explained in this document.

On July 9, 1981, BPA staff presented an explanation of the initial proposal of the ASC methodology to the joint State board appointed by FERC in Seattle, Washington. Section 9(g) of the Regional Act authorizes FERC to convene this joint State board to assist it in reviewing the rates for the sale of power from investor-owned utilities to BPA.

The consultation process continued after the publication of BPA's initial proposed methodology, with additional working group meetings being held during the public comment period. Tape recordings or detailed notes of the meetings were made part of the official record.

Pacific Power & Light Company (PP&L) presented, for discussion purposes, a draft computation of ASC for PP&L in Washington State using the proposed methodology. The PP&L sample provided an opportunity for evaluating the methodology.

Major issues discussed during the public comment period were treatment in the ASC methodology of: (1) crediting of secondary power sales and miscellaneous services revenues, (2) functionalization of revenue related taxes, (3) retroactive return of costs of construction work in progress for terminated plants, and (4) rate of return on equity for public agencies. Each of these issues is discussed in detail in Section V.

II. Legal Requirements.

A. Regional Act Provisions.

The provision for an exchange of power and a related ASC methodology is found in section 5(c) of the Regional Act. Sections 5(c)(1) and 5(c)(7), are particularly germane to the development of the ASC methodology. Section 5(c) is as follows:

> "5(c)(1) Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.
>
> "(2) The purchase and exchange sale referred to in paragraph (1) of this subsection with any electric utility shall be limited to an amount not in excess of 50 per centum of such utility's Regional residential load in the year beginning July 1, 1980, such 50 per centum limit increasing in equal annual increments to 100 per centum of such load in the year beginning July 1, 1985, and each year thereafter.
>
> "(3) The cost benefits, as specified in contracts with the Administrator, of any purchase and exchange sale referred to in paragraph (1) of this subsection which are attributable to any electric utility's residential load within a State shall be passed through directly to such utility's residential loads within such State, except that a State which lies partially within and partially without the region may require that such cost benefits be distributed among all of the utility's residential loads in that State.
>
> "(4) An electric utility may terminate, upon reasonable terms and conditions agreed to by the Administrator and such utility prior to such termination, its purchase and sale under this subsection if the supplemental rate charge provided for in section 7(b)(3) is applied and the cost of electric power sold to such utility under this subsection exceeds, after application of such rate charge, the average

system cost of power sold by such utility to the Administrator under this subsection.

"(5) Subject to the provisions of section 4 and 6, in lieu of purchasing any amount of electric power offered by a utility under paragraph (1) of this subsection, the Administrator may acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sale if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

"(6) Exchange sales to a utility pursuant to this subsection shall not be restricted below the amounts of electric power acquired by the Administrator from, or on behalf of, such utility pursuant to this subsection.

"(7) The 'average system cost' for electric power sold to the Administrator under this subsection shall be determined by the Administrator on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission. Such average system cost shall not include--

"(A) the cost of additional resources in an amount sufficient to serve any new large single load of the utility;

"(B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and

"(C) any costs of any generating facility which is terminated prior to initial commercial operation."

In addition, section 3(18) of the Regional Act states:

"'Residential use' or 'residential load' means all usual residential, apartment, seasonal dwelling and farm electrical loads or uses, but only the first four hundred horsepower during any monthly billing period of farm irrigation and pumping for any farm."

Section 9(g) establishes a process for reviewing rates for the sale of power by an investor-owned utility to the Administrator under Section (c) as follows:

" (g) When reviewing rates for the sale of power to the Administrator by an investor-owned utility customer under section 5(c) or 6, the Federal Energy Regulatory Commission shall, in accordance with section 209 of the Federal Power Act (16 U.S.C. 824h) --

(1) convene a joint State board, and

(2) invest such board with such duties and authority as will assist the Commission in its review of such rates."

Pursuant to the above provisions, particularly section 5(c)(7) of the Regional Act, I have developed a proposed final methodology, as set forth more fully herein and as included as Exhibit C to the Residential Purchase and Sales Agreement.

B. Environmental Determination.

Department of Energy regulations state that neither an environmental assessment nor an environmental impact statement is required where it is clear that the proposed action is not a major Federal action significantly affecting the quality of the human environment. BPA has completed a Brief Memorandum that demonstrates that the adoption of the proposed average system cost methodology would not significantly affect the quality of the human environment. This memorandum is available from Bonneville's Environmental Manager.

III. Calculation of ASC.

Prior to discussing the specific issues addressed in the methodology, it is necessary to briefly summarize the primary features of the methodology and the procedures to be used in reviewing rates computed pursuant to the methodology. In general, the ASC of a utility's resources is determined by dividing the utility's eligible generation and transmission costs (contract system costs) by its eligible load (contract system load) to derive a figure in mills per kilowatthour. One of the general principles I have followed in developing this methodology is that BPA will be acquiring the electric power resources offered to it at the power supply level. This principle defines the costs and loads to be included in the calculation of ASC as those related to production and transmission and excludes distribution-related costs and loads. The Regional Act in Section 5(c)(7) requires that certain other costs be excluded from the determination of ASC. These are (1) the costs of resources serving new large single loads, (2) the costs of resources serving extraregional load growth, and (3) the costs of resources that are terminated prior to initial commercial operations.

The utility will provide costs and loads on six schedules identified as Appendix 1 to Exhibit C of the Residential Purchase and Sale Agreement. The six schedules in Appendix 1 are: Schedule 1 - Plant Investment/Rate Base/Rate-of -Return, Schedule 2 - Capital Structure and Cost of Capital, Schedule 3 - Expenses, Schedule 4 - Income Taxes, Schedule 5 - Average System Cost, and Schedule 6 - Jurisdictional Amount. Regulated electric utilities generally are required to maintain their accounts according to a Uniform System of Accounts prescribed by the FERC. To standardize reporting and assure greater uniformity in the separation of costs between functions, the cost data submitted on the ASC schedules is to be consistent with the FERC Schedule 3 - Expenses, Schedule 4 - Income Taxes, Schedule 5 - Average System Cost, and Schedule 6 - Jurisdictional Amount. Regulated electric utilities generally are required to maintain their accounts according to a Uniform System of Accounts prescribed by the FERC. To standardize reporting and assure greater uniformity in the separation of costs between functions, the cost data submitted on the ASC schedules is to be consistent with the FERC Uniform System of Accounts.

A. Determination of Contract System Costs.

The determination of contract system costs begins when a body that has jurisdiction over retail rates (commission) approves a revision in the utility's retail rates. For investor-owned utilities, this body will be the state utility commission. For municipalities, public utility districts, and cooperatives, it will be the utility governing body. The utility will submit the approved costs to BPA on the Appendix 1 schedules. For those utilities that operate in more than one jurisdiction, the utility will provide BPA with its total system costs for its multiple jurisdictions on Schedule 6. In this case, the utility's jurisdictional total system costs will be determined by the allocation procedures used by the appropriate commissions. This jurisdictional allocation of costs also excludes the cost of plants necessary to serve extraregional load growth, as required by the Regional Act.

Contract system costs may be generally defined as equal to the sum of the following: (1) the eligible rate base times the authorized rate of return and (2) eligible operating expenses (net of certain revenue offsets). The cost items that comprise the rate base will be submitted on Schedule 1. These cost items include total gross plant, depreciation reserve, accumulated deferred taxes and working capital. On Schedule 1 the total jurisdictional rate base is separated into the following categories: excluded items (*i.e.*, new large single load and the cost of terminated facilities production, transmission, and an "other" rate base category (mainly distribution). Only the production and transmission rate base is included in the calculation of ASC. The final step in Schedule 1 is to multiply the authorized jurisdictional rate-of-return by the rate base to yield a test period return on investment.

Schedule 2 identifies for the test period the absolute and relative dollar amounts for each component of the utility's capital structure (*i.e.*, debt, preferred stock, and common equity). Furthermore, both the percentage cost of each component and an overall weighted percentage cost of capital are shown. It is this overall weighted cost of capital (*i.e.*, rate-of-return) that is applied to the rate base in Schedule 1.

Schedule 3 lists the test period expenses for items such as fuel, purchased power, operation and maintenance, and income and other taxes. In addition, Schedule 3 specifies that the revenues from special services such as nonfirm energy sales are to be subtracted from the test period expenses before calculating the costs included in the ASC. As with Schedule 1, the expenses reported on Schedule 3 are placed in the excluded category and separated by function based on the FERC system of accounts and instructions included in the footnotes.

Schedule 4 describes the test period calculation and functionalization of Federal income tax. The income tax expense calculated in Schedule 4 is carried forward to Schedule 3 and included with other test period expenses.

B. Determination of Contract System Load.

Schedule 5 is the utility's calculation of its contract system load. To determine the contract system load, the utility's miscellaneous services sales are subtracted from the utility's total system load as approved for retail ratemaking purposes by the commission for the jurisdiction. To this load is added distribution losses associated with the net total system load. Finally, the utility will deduct its excluded resources load and associated losses. Once the contract system load is determined it will be divided on Schedule 5 into the contract system cost from Schedule 3 to obtain the average System cost.

IV. ASC Review Procedures.

All of the parties in the consultation process wanted BPA to maintain a significant role in the review function in order to insure compliance with the methodology. However, the parties generally agreed that BPA should not conduct an independent audit of the decisions made by the commissions believe the review process contained in the methodology and described is consistent with these goals.

A. Procedures for Filing Costs and Loads with BPA.

The utility must complete and file an Appendix 1 with BPA for each jurisdiction in which it desires to exchange power with BPA. Each time the utility files for a jurisdictional rate change or otherwise commences a rate change proceeding the utility will file with BPA an Appendix 1 setting forth its proposed system costs and loads. In addition, each time the utility receives either interim or final approval of the rate proposal, the utility must file a new Appendix 1 with BPA reflecting the approved costs. The ASC of this Appendix 1 will be applied, subject to change, during the period of time the utility's jurisdictional rate schedules are in effect (exchange period), and will apply to the amount of power purchased by BPA from the utility.

B. BPA Review Process.

Each Appendix 1 will be reviewed by BPA for accuracy, conformance with the methodology, and consistency with generally accepted accounting principles. BPA's review of a utility's Appendix I will be as prompt as reasonably possible and will result in a written report. I may authorize an increase or decrease in the ASC for the utility's relevant exchange period based upon the findings of the written report. Pursuant to my findings, BPA will recover the excess or pay the deficiency with interest.

BPA's regional power sales customers and other interested persons will be allowed an opportunity to comment in writing on each Appendix 1 filed with BPA by a utility. Each utility that files an Appendix 1 will mail notice to each of BPA's regional power customers and other interested parties in accordance with a list provided by BPA. The utility and BPA will permit such customers and interested parties to examine each Appendix 1 submitted to BPA. All comments that BPA receives will be included as part of the record supporting the ASC determined by BPA.

C. FERC Review Process.

Each utility that is subject to the FERC's jurisdiction under Part II of the Federal Power Act must file BPA's written report, the ASC determined by BPA, and the utility's Appendix 1 with FERC. This filing by the utility will be deemed to be in compliance with Section 205(c) of the Federal Power Act. The utility may contest any ASC adjustment made by BPA in any ASC review proceeding before FERC, its delegate or successor and may argue for an ASC calculated pursuant to the Appendix 1 originally filed with BPA.

The utility must notify of its** filing with FERC all parties that submitted comments to BPA on the utility's Appendix 1. The FERC will publish notice of the Utility's filing in the FEDERAL REGISTER. If one or more members of FERC, its delegate or successor determine that a issue of fact or law exists, an opportunity for oral presentation of arguments will be provided to the parties.

FERC's review of a utility's ASC will be to determine whether the ASC was determined in accordance with the methodology. If the FERC, its delegate or successor, finds that it was not it may order the ASC be changed. FERC will publish its final order approving or disapproving the ASC in the FEDERAL REGISTER. If a final order of FERC revises the ASC, the injured party will be compensated with interest as ordered.

D. Change in ASC Methodology.

The proposed ASC methodology provides a method for changing the methodology if BPA or the participants in the exchange find it does not function properly, to allow for changes in accounting procedures, or for changes in circumstances relating to the exchange. A consultation process similar to the one used to develop this proposal will be conducted in order to change the methodology. However, no effort to change the methodology may begin prior to one year after FERC's approval of any current methodology.

V. Issues.

A. Jurisdictional Costing Approach.

From the outset of the consultation process it has been apparent to all parties that the development of a methodology to determine an ASC that is consistent with the provisions of the Regional Act would require creative, yet reasonable solutions to a variety of complex matters. In developing the ASC methodology one of the primary matters that had to be resolved was the overall approach for determining the basic cost and other data needed to calculate an ASC.

During the initial stages of the consultation process considerable time was devoted to two basic alternative ASC methodologies: (1) a methodology based on an independent determination of the relevant costs; or (2) a methodology based on the findings of retail ratesetting bodies modified by specific instructions required by the Regional Act. Agreement has been reached by the consulting parties that the costs allowed or established for retail ratemaking purposes should be used in calculating ASC, subject to certain specific requirements. This jurisdictional approach will substantially reduce the number of matters that would require separate treatment in the methodology. For example, if the methodology did not utilize the findings of the commission with jurisdiction over the retail rates of an IOU participating in the exchange, an approach for determining the return on common equity to be allowed in calculating ASC would have to be devised. While it may be possible to design such a method, the processes used in retail rate proceedings will produce findings that are appropriate for use in ASC calculations, particularly with regard to matters concerning overall utility revenue requirements. In determining retail rates, the commissions make informed decisions on matters such as test periods, rate base, construction work in progress, and rate of return. The use of those findings simplifies and limits the matters to be determined within the ASC methodology. The jurisdictional approach leaves to regulatory authorities the complex issues involved in determining overall revenue requirements and thereby avoids intrusion by BPA into rate issues that are competently dealt with by bodies already delegated these responsibilities.

Since the jurisdictional approach ties ASC to the overall costs used in establishing retail rates and since the ASC methodology provides for adjustments of ASC contemporaneous with retail rate changes, the jurisdictional approach will likely result in reductions in retail rates for residential consumers that are in direct relationship to the production and transmission costs used in determining those rates. This result is consistent with Section 5(c)(3) of the Regional Act, requiring that the cost benefits of the exchange be passed directly through to the utility's residential loads.

Several utilities that are potential participants in the exchange are subject to more than one retail rate jurisdiction. Therefore, consistent with the use of this jurisdictional approach, the methodology provides that a separate ASC will be calculated for each jurisdiction in which the utility elects to enter into the exchange. When a multiple jurisdictional utility files a retail rate case in one jurisdiction and the costs and rates are approved by the appropriate commission, the ASC for that utility in that jurisdiction can be modified. This methodology assures that the benefits of the exchange for a utility's residential customers are closely tied to the retail rate calculation.

In summary, I recognize that it may be possible to establish a methodology that independently develops a single utilitywide ASC for exchanging utilities. However, the jurisdictional approach, using existing regulatory procedures, provides a simple and equitable means for resolving revenue requirement issues relevant to the ASC calculation.

B. Functionalization Procedures.

1. General Procedures.

The use of the findings of a commission in a retail rate proceeding reduces the need for independent determinations in calculating ASC. However, commission findings typically address only the utility's overall revenue requirement and various rate design matters, rather than the separation of costs between distinct utility functions as is necessary for ASC calculations. This separation of costs or functionalization is important to the determination of ASC because only production and transmission costs are included in the ASC. Other activities and costs, primarily those associated with the distribution of electric power, are not undertaken or incurred at the power supply level, and are therefore not allowed in the exchanging utility's ASC.

Accordingly, in the ASC methodology I have adopted procedures to differentiate between costs that are included in ASC and those that are not. While for some functions the related costs are clear, there are others where the appropriate functionalization treatment is not apparent. Therefore, to assure uniform functionalization, the procedures to be used in the ASC methodology are described in a series of footnotes to specific line items listed in Appendix 1 of Exhibit C.

Generally, I have adopted a three-part functionalization approach in the ASC methodology. These methods are: (1) use of Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts, (2) reliance on analytical studies prepared by the exchanging utility that demonstrate the functional nature of an item, and (3) use of footnotes that specify functionalization treatment, either by use of a formula or by direct functionalization to a specific category. I have elected to use the FERC accounting system whenever possible to accomplish the appropriate functionalization. The FERC accounting system specifies the functionalization of a large portion of a utility's investments and expenses. Therefore, the use of this system in the ASC methodology will reduce the need for separate functionalization procedures. The ASC methodology requires that if a utility does not follow the FERC accounts, the Appendix 1 filing must include a reconciliation between its accounts and the items allowed in calculating ASC.

As a second part of the functionalization process, I have elected to include, by footnotes, some procedures that provide the filing utility with an opportunity to demonstrate, by separate analysis, the functional nature of an item. In cases where an item is not initially charged directly to a particular function, the filing utility may have sufficient information to clearly demonstrate the functional nature of that item. In the absence of this opportunity, a functionalization approach would have to be specified for all the items not directly functionalized under the FERC accounting system. I have elected to allow some flexibility in the methodology, because the parties participating in the consultation process felt strongly that an overly rigid approach would not adequately recognize the varied items involved in providing utility service. It is apparent that allowing a filing utility an opportunity to demonstrate (by a special analysis) that a particular functionalization is appropriate can lead to disagreements with BPA as to the adequacy of the functionalization analysis and the conclusions. At this time, however, I am adopting an ASC methodology that provides some flexibility regarding functionalization rather than an approach that depends entirely on formulas.

The third step in the functionalization process involves the use of specific functionalization formulas. In general, these formulas or ratios are based on plant and/or expense data and are to be used for items for which the formula is a reasonable estimate or approximation of the actual functional nature of an item. This approach establishes the reasonable functionalization of costs in the absence of detailed cost information or where the administrative cost of collecting and analyzing detailed cost information is unwarranted.

With respect to the possibility of using the formulas in conjunction with special functionalization analyses, the ASC methodology is not designed to allow a filing utility to pick and choose between a separate analysis and the specified formula for each item in order to maximize the costs functionalized to production and transmission. If a utility elects to demonstrate by a separate analysis that certain costs should be functionalized in a particular manner, that utility must demonstrate why the formulas, rather than separate analyses, were used for other items. In other words, under the ASC methodology the filing utility is not free to choose between the methods (*i.e.*, separate analysis or specified formula) on the basis of which method functionalizes more costs to production and transmission.

2. Revenue related taxes.

Following the publication of the initial proposal and during the review of the PP&L sample, concerns arose as to the treatment of revenue-related taxes. Specifically, in the PP&L sample the test-year costs related to the State of Washington's Business and Occupation (B&O) tax (collected pursuant to Wash Rev Code § 82.04.240 *et. seq.* and 82.16.020) were functionalized based on the functionalization of the total revenue requirement. The B&O tax in question is applied to the retail sales revenue of PP&L.

PP&L argued that its functionalization was correct on a cost causation basis. The B&O tax is applied to retail revenues which are based on the utility's total costs which include generation, transmission, and distribution/other components. Therefore, ~~we have decided~~ [it was argued (erratum)] that the tax should be functionalized according to the functionalization of all other costs.

The DSIs argued that functionalization should be based on a hypothetical disaggregation of the utility into a generation and transmission entity and a distribution entity. Only costs which would be included in the charge made by the generation and transmission entity to the distribution entity should be included in ASC. Because the B&O tax is incurred only at the distribution level, it would not be part of the that charge.

The DSIs also point out that BPA's preference customers in the State of Washington also pay the B&O tax. Therefore, wholesale residential rate parity between preference customers and exchanging utilities will be maintained without inclusion of the B&O tax in ASC. Inclusion of that tax in ASC would also provide an incentive for those preference customers in the State of Washington to exchange.

In my judgment it is more appropriate to functionalize expenses incurred at the retail level to distribution/other. Therefore, I have adopted a functionalization footnote (see footnote 3) requiring that revenue taxes related to retail sales, and other items unrelated to the power supply level such as bad debt expense, be functionalized to distribution/other.

C. Losses.

During the initial consultation process it was agreed that distribution losses included in Schedule 5 of the exchange contract would be established based on an engineering study submitted with Exhibit C. In BPA's initial ASC proposal the footnote associated with distribution and excluded load losses read as follows: "Loss factors per an engineering study that is submitted to Bonneville by an exchanging utility, subject to review by Bonneville. Such study shall be in sufficient detail so as to ac accurately identify losses associated with (a) the distribution function line related losses), and (b) serving excluded loads."

After reviewing the PP&L sample calculations of the ASC proposal noting that the only distribution losses PP&L included were those associated with the secondary distribution system, it was suggested that a more precise definition of the items included in the study was necessary. Subsequently, footnote 17 was modified to read: "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 used by the commission for the purpose of establishing retail rates. Losses shall be established according to a study (engineering, statistical or other) that is submitted to Bonneville by the exchanging utility, subject to review by Bonneville. Such 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."

D. Treatment of In-Lieu Taxes.

During the consultation process concern was expressed with regard to the treatment of in-lieu taxes included in the retail rates of publicly owned utilities. It was felt that local governments would have an incentive to increase in-lieu taxes paid by locally owned and operated utilities participating in the exchange, thus putting the burden of paying these additional taxes on the region's ratepayers through the exchange. The IOUs and DSIs felt in-lieu taxes should be included in the ASC calculations, but only to the extent that nontax-exempt utilities would pay these taxes for the various levels of local governments. To alleviate the concerns expressed, the following footnote (footnote 14) was agreed to and included to Exhibit C.

"A tax-exempt utility may include in-lieu taxes up to an amount that is comparable, for each level of Government paid in-lieu taxes, with taxes which would have been paid by a nontax-exempt utility to that unit of government, but in no event shall the jurisdictional total in column 2 be greater than the actual amount paid."

E. Extent of BPA Review.

One of the primary features of the final proposed ASC methodology concerns BPA's review of the Appendix 1, Exhibit C. The jurisdictional approach significantly reduces the depth of the BPA review necessary for a filed Appendix 1. However, given the number and complexity of calculations that go into a retail rate case and the particular steps required in calculating ASC by the provisions of Exhibit C, the parties to the consultation process concurred that it is necessary that BPA review and adjust, if necessary, the filed ASC rate. Accordingly, I included provisions in the ASC methodology that require BPA to review the filed ASC determination for consistency with the provisions of the ASC methodology. Further, should the filed ASC rate be calculated in a manner that is inconsistent with Appendix 1, the ASC methodology requires that BPA make an adjustment to the rate.

F. Treatment of Secondary and Miscellaneous Services Sales Revenues.

I believe it is appropriate to credit a utility's secondary and miscellaneous services revenues against its eligible exchange costs before deriving its contract system costs. This was the approach favored by the DSIs and public agencies.

I have several reasons for crediting these revenues when determining contract system costs. Public utility commissions and other utility regulatory bodies commonly credit secondary and miscellaneous services revenues against a utility's total costs in order to determine the revenue requirement for all other customer groups. BPA will be paying through the exchange a substantial portion of the fixed costs of the utility's resources that produce secondary and miscellaneous services sales revenues. Therefore, BPA should share in the benefits of these sales. In addition, BPA's Priority Firm (Section 7(b)) rate, that is applicable to sales to an exchanging utility, is lower than it otherwise would be because revenues from Federal secondary and miscellaneous services sales are credited against Federal base system costs. The utility will receive the benefit of BPA's secondary and miscellaneous services sales, so I find it appropriate that BPA (and its customers who purchase from the exchange resource pool) should receive a proportional share of the benefits of the utility's secondary and miscellaneous services sales.

I considered another treatment of secondary and miscellaneous services revenues that was proposed by the investor-owned utilities and public utility commissions. It was suggested that revenues be credited only up to the incremental costs of the secondary and miscellaneous sales. The IOUs, in advocating this position, cited this treatment as having been used in the Pacific Northwest Utility Coordinating Committee's 4000 Average Megawatt Purchase from Investor-Owned Utilities draft contract. This draft contract, published in 1977, represented the early efforts of Pacific Northwest bodies to effect an exchange of Federal and non-Federal power. The IOUs also argued that the retail rates of residential customers include the benefits from secondary and miscellaneous sales revenues, and consequently, treating these revenues in the methodology in a manner that benefits BPA rather than the utility's residential customers is inappropriate. The IOUs argued in relation to this point that their method would maintain cost parity between an exchanging IOU and a nonexchanging generating public utility that is allowed to "retain" its secondary revenues. Finally, the IOUs asserted that utility retail regulatory commissions have no jurisdiction for ratemaking purposes to fix the rates and, hence, the revenues derived from a utility's nonfirm sales.

I did not choose this alternative for the following reasons. Most commissions credit all of secondary and miscellaneous services revenues against total costs, not just the incremental costs. The intent of the ASC methodology is to utilize the same costs allowed by a utility regulatory commission to establish the utility's retail revenue requirement. Retail rates are based on the net costs of resources reflecting the commission's determination of opportunity revenues and the application of those revenues to reduce gross costs. I believe that through the exchange BPA will become a ratepayer of the exchanging utility; therefore, I conclude that BPA should be treated no differently than any other ratepayer of the utility. Consequently, BPA should receive the benefits of secondary and miscellaneous services revenues as do other customers of the utility.

Furthermore, I do not agree that the exchanging IOU and a nonexchanging generating public utility are being treated differently under my proposal. To the extent that the consumers of each are being served by its own resources, the consumers of each will receive the secondary benefits of the utility's own resources used to serve them. The retail rates of a nonexchanging generating public utility are the melded costs of the utility's own and BPA resources, whereas an exchanging IOU's retail rates will be based on one or the other, but each utility receives the secondary benefits from its own resources and from BPA resources to the extent that each is used to serve the utility's loads.

G. Billing Credits.

The Regional Act in Section 6(h) requires BPA to grant billing credits to customers for independent conservation activities and for resource construction. The credit for independent conservation activities, including retail rates, is to be equal to the savings resulting from those activities. Although specific aspects of BPA's billing credits policy have yet to be formulated, it is possible that billing credits for conservation may exceed the cost of those activities.

The consultation process identified three possible treatments of conservation costs and corresponding billing credit revenues. The cost of the conservation program could be included in contract system costs with no offset from the revenues. This treatment would provide the maximum incentive for utilities to undertake conservation. However, it would result in BPA paying twice for the conservation program, first in the form of the billing credit and second in the ASC rate.

A second alternative would be to credit all the billing credit revenues against contract system costs. Proponents of this alternative assert that billing credits should be treated for ASC purposes in the same manner as opportunity revenues and as they are used in establishing retail rates. Residential ratepayers from exchanging utilities would benefit only as the whole region benefits from a conservation program.

I have decided that the most appropriate treatment of billing credit revenues is to credit them against contract system costs only up to the cost of the corresponding conservation program. This treatment is equivalent to excluding from contract system costs both the costs of the conservation program and all billing credit revenues. This treatment is consistent with two purposes of the Regional Act: regional wholesale rate parity for residential consumers and the development of cost effective conservation programs. Consumers served by BPA's public agency customers and residential consumers of exchanging utilities will face a wholesale power cost equal to BPA's Priority Firm rate. All consumers' rates will be reduced by the excess of the billing credit revenue over the costs. Therefore, with respect to billing credits, this proposal will maintain wholesale residential rate parity within the region.

This proposal also insures that each utility in the region will have the incentive to develop independent conservation programs. The Intercompany Pool (ICP) submitted an analysis demonstrating that under certain assumptions, the residential ratepayers of an exchanging utility would be affected adversely by the region's billing credit program. Although I agree with the DSIs that the validity of the ICP analysis partially depends on its unrealistic assumption that the billing credits are funded entirely by the Priority Firm (7(b)) rate, I agree that the consumers of a utility should receive the direct benefits of that utility's independent conservation programs. The full credit approach would spread some of those direct benefits to the region as a whole, whereas the approach I am proposing allows the utility's consumers to keep all benefits from independent conservation programs.

H. Terminated Facilities.

Section 5(c)(7)(C) of the Regional Act requires that the average system cost shall not include "any costs of any generating facility which is terminated prior to initial commercial operation." This provision raised two issues that are discussed below. There is, however, no issue or disagreement regarding any jurisdiction's (*e.g.*, a State utility commission or public agency board) right to allow or disallow construction work in progress in a utility's retail rate base.

1. The first issue is whether to exclude the costs of a generating facility that was terminated prior to the effective date of the Regional Act (*i.e.*, whether the Regional Act was retroactive regarding costs of terminated facilities). The direct-service industries' position is that the costs should be excluded even if the termination occurred prior to enactment. They base their argument on the fact that the exclusions in (A) and (B) of Section 5(c)(7) set forth effective dates, while the (C) exclusion does not, indicating that it was not intended to be so qualified.

While it is true that the clause on terminated facilities contains no qualifiers as to dates, there is a strong preference for prospective rather than retroactive effect in a statute, absent a clear legislative intent to the contrary (*Sutherland on Statutory Construction*, 41.04). I found no clear indication of such a contrary intent. Additionally, the section is written in the present tense ("facility which is terminated"), which demonstrates an intent for prospective application, *Washington State Director's Association v Dept of Labor and Industries*, 82 Wash.2d 367 (1973). Therefore, I have determined that the ASC will exclude costs of those generating facilities terminated after the effective date of the Regional Act, but may include costs of those terminated prior to that date if such costs are included by the Commission in the utility's retail rates.

2. The second issue is whether construction work in progress (CWIP) should be allowed in the ASC, and if allowed, whether it can be recovered. BPA received public comments to the effect that CWIP should be excluded from the calculation of ASC. It was argued that allowing CWIP will disadvantage those States that exclude CWIP and will provide an incentive for State utility regulatory commissions to include CWIP. It also was stated that allowing CWIP tends to bias investment decisions in favor of large thermal plants and is contrary to the Oregon statute, adopted by referendum, that disallows CWIP in the State of Oregon for IOUs. Exclusion of CWIP also would solve the problem of retroactive recovery of terminated plant costs.

I have decided that the ASC methodology should not deviate from the jurisdictional approach in this matter. I want to emphasize that I have not decided to include or exclude CWIP, but instead to accept State or local determinations on this issue. Arguments on the merits of CWIP inclusion can be made in each jurisdiction. This approach is consistent with the legislative history of the Regional Act. An amendment to specifically exclude CWIP from ASC was rejected by House vote during congressional debate on the Regional Act (Cong. Rec. H10616, Nov. 13, 1980). Commissions often try to balance decisions on issues such as CWIP, return on equity, future versus historical test year, and tax normalization. Therefore, it would not be appropriate to accept the commission decision concerning other controversial or subjective issues, but overturn that decision concerning CWIP.

Some parties argued that once CWIP was included, there should be no retroactive recovery of the costs if the plant is later terminated. However, I find that the plain language of Section 5(c) 7(c), stating that "any costs of any" terminated facility must be excluded, requires that retroactive adjustment be made. (emphasis added)

I recognize that retroactive recovery involves a very complicated unwinding of cost determinations and that the potential for recapture may create contingent liabilities for the utility that may tend to raise the utility's cost of capital. Therefore, I am proposing a method for computing recovery that may lower the probability of retroactive recovery. If the CWIP included in the rate base is associated with a specific generating facility and that facility is later terminated, then BPA will recover all payments made resulting from including that CWIP. If, however, the CWIP included is not identified with particular plants, BPA will recover revenue only to the extent that the amount of CWIP included in the rate base exceeds the CWIP account for plants other than terminated facilities.

I. Return on Equity for Public Agencies.

Investor-owned utilities generally are allowed a return on the common equity portion of their rate base that is sufficient to attract capital and is approximately equal to the return being earned on investments of similar risk. A publicly owned utility does not have stockholders requiring a return on their investment. However, most publicly owned utilities do regularly earn a positive net income; that is, their revenues generally are greater than the sum of annual operating expenses, taxes, depreciation, and interest.

The need for a positive net income is usually caused by annual capital expenditures in excess of annual depreciation expense. These expenditures are for system expansion, system improvements, and the effects of inflation on the cost of replacements. To the extent that the utility chooses not to finance this excess completely with debt, some of the capital expenditures have to be financed out of current revenues.

The DSIs argue that no return on equity should be allowed for public agencies because depreciation expense is the accepted accounting technique for assigning capital costs to time periods. An allowance for a return on equity in ASC would permit public agencies to shift capital costs to the period of the exchange contract.

On the other hand, the Public Power Council advocates that the ASC methodology allow the same return on equity as is included in the utility's retail rates. This approach, it is argued, is consistent with the jurisdictional approach and allows the publicly owned utility flexibility[**] to react to changing market conditions and to minimize their total cost of capital. The region is protected through intervention rights in the rate setting process, BPA's ASC review procedures, and the publicly owned utility's commercial and industrial customers.

I do not agree with the DSIs that no return on equity should be allowed publicly owned utilities. Because of factors mentioned previously, exchanging publicly owned utilities' rate bases are likely to be growing rapidly in the near future. Sound business practice dictates that only a portion of this capital expansion be financed out of debt. Allowance for no return on equity in the ASC methodology might well induce publicly owned utilities to rely on debt more heavily than would be prudent, thus driving up the cost of debt and ASC.

Therefore, I am proposing that publicly owned utilities be allowed a return on equity equal to their demonstrated need for revenues in excess of operating expenses, taxes, depreciation, and interest expense. This demonstrated need generally will be in the form of debt coverage or equity ratio requirements to maintain credit ratings. Public agencies will be able to minimize their financing cost, but at the same time will be encouraged to debt finance a major portion of major capital items, thus spreading the costs of those items over the time when they will be used.

J. Preference Customer Transmission Facilities.

Some of BPA's public agency preference customers, even though they purchase all or nearly all their power from BPA, have facilities and expenses that would be functionalized to transmission under the provision of the proposed ASC methodology. Fifty-one of BPA's preference customers listed some transmission expense on their 1979 financial statements. Without a special provision in the methodology, full requirement customers (customers receiving all of their power from BPA to meet their customers'[**] needs) would be able to enter into the exchange and recover a portion of their transmission costs.

The DSIs argued that full requirements preference customers should not be allowed to exchange to recover transmission costs. Wholesale rate parity would not be served by shifting transmission costs to BPA, because those customers already have access to and are served at the Priority Firm 7(b) rate. They argued that economic benefits must have been the impetus for constructing transmission facilities, and the utility would earn double benefits if it were allowed to exchange.

During the consultation process, public agency preference customer representatives asserted that the broad language of the Regional Act precluded identification and specific exclusion of preference customer transmission costs from calculation of ASC. They argue that investor-owned utilities may have similar transmission costs that would be included in ASC.

In order to preclude preference customer transmission exchanges, I considered including a provision that customers who include power purchased at the 7(b) rate in their ASC be limited in their inclusion of transmission costs to the sum of (1) cost of facilities directly related to the utility's own generation or non-7(b) power purchases, and (2) a pro rata share of the remaining transmission costs based on the ratio of test year energy load served from non-7(b) sources to total test year energy load.

However, I decided not to include such a provision. Bonneville has tended to build transmission and subtransmission facilities for smaller rural utilities that it will not build for larger urban utilities. I find that a partial regional sharing of the costs of these facilities, although not specifically intended by the Regional Act, is consistent with postage stamp rates. Investor-owned utilities do have facilities of this nature which will be included in ASC. Exclusion of them for preference agencies would have at least an appearance of discrimination. Because of the relatively small cost involved, DSI representatives have withdrawn their opposition to inclusion of these costs based on a desire to achieve agreement on as many ASC issues as possible.

K. New Large Single Load.

Section 5(c)(7) of the Regional Act specifies that average system costs shall not include the costs of additional resources in an amount sufficient to serve any new large single load of a participating utility.

"New Large Single Load" is defined as any load associated with a new facility, an existing facility, or an expansion of an existing facility which (a) is not contracted for, or committed to, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and (b) will result in an increase in a customer's power requirements of ten average megawatts or more in any consecutive 12-month period.

The costing of resources associated with new large single loads is complicated by the fact that generating and bulk transmission facilities are rarely identified with particular loads. Instead a utility serves all its load with all of its resources at melded rates.

It was generally agreed during the consultation process that the legislation intended that the costs excluded from ASC for new large single loads should reflect the utility's incremental cost for resources when service to the load commenced. Alternative costing methods considered included BPA's New Resources (7(f)) rate, a pool of resources not dedicated to a utility's load as of September 1, 1979, and the utility's avoided costs at the time service to the load began as calculated pursuant to Section 210 of the Public Utilities Regulatory Policies Act. The parties to the consultation were able to agree to a method combining the first two alternatives.

The procedures for calculating the cost of additional resources sufficient to serve any new large single load is contained in footnote 15(b) to the Appendix 1 tables. To the extent the utility has the following resources, the cost of serving new large single loads will be the cost (in the following priority) of: (1) resources dedicated to the load; (2) power purchased from BPA at the New Resources (7(f)) rate; (3) a pool of the utility's resources not committed to its load as of September 1, 1979; and (4) the most recently acquired other baseload resource or long term power purchase.

I agree that this method should provide an accurate yet administratively feasible method of costing the resources necessary to serve new large single loads.

Issued at Portland, Oregon this 26th day of August 1981.

Peter T. Johnson
Administrator

Average System Cost Methodology

I. Summary

This exhibit sets forth the method for computation and payment of “average system cost” for the purpose of an exchange of power between Bonneville and a Utility pursuant to section 5(c) of Public Law 96-501 (Regional Act). The method provides that for an exchanging Utility the average system cost (ASC) is: the costs allowed or established for retail ratemaking that are eligible for exchange divided by the kilowatthours of load assumed for retail ratemaking, adjusted consistent with this methodology. Under this method, a separate ASC will be calculated for each exchanging Utility for each jurisdiction in which the Utility does business. Each ASC so calculated will be changed when revised retail rates go into effect.

This exhibit sets forth specific procedures for reporting cost items and recognition of those items in determining ASC, including procedures for the exclusion of particular costs as required by statute. The exhibit also sets forth the procedures for the filing of relevant data by the Utility and for the review of that data by Bonneville.

II. Definitions

The following definitions apply to all sections of Exhibit C.

A. “Average System Cost” or “ASC” means for each Jurisdiction and each Exchange Period the quotient obtained by dividing Contract System Costs by Contract System Load.

B. “Commission” means a State regulatory body, preference Utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

C. “Contract System Costs” means the Utility’s costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in, jurisdictionally allocated by, and subject to the provisions of Appendix 1. Contract System Costs do not include costs required to be excluded from ASC by section 5(c)(7) of the Regional Act; the exclusion of these costs is provided for in Footnote 15 to Appendix 1.

D. “Costs” means the aggregate dollar amount or any portion of the amount allowed or relied upon by the Commission to determine the Test Period revenue requirement for the Utility in a Jurisdiction.

E. “Exchange Period” means the period of time during which a Utility’s Jurisdictional retail rate schedules are in effect, commencing with the effective date of these schedules and ending with the effective date of new retail rate schedules in the Jurisdiction; provided that no Exchange Period shall commence prior to or extend beyond the term of the Utility’s Residential Purchase and Sale Contract Agreement.

F. "Contract System Load" means the firm energy load used by the Commission for the purpose of establishing retail rates, adjusted pursuant to Appendix 1.

G. "Jurisdiction" means the service territory of the exchanging Utility within which a Commission has authority to approve the retail rates.

H. "New Large Single Load" means that load defined in section 3(13) of the Regional Act, and as determined by Bonneville as specified power sales contracts with its customers.

I. "Regional Power Sales Customer" means any entity that contracts directly with Bonneville for the purchase of power for delivery in the region as defined by section 3(14) of the Regional Act.

J. "Test Period" means the time period, not to exceed 12 months, used by the Commission to determine Costs for retail ratemaking.

III. Procedures for Determining Average System Cost

The procedures set forth in this section will enable Bonneville to determine the ASC, in accord with the methodology in Appendix 1, for each exchanging Utility for each Jurisdiction within the region where the Utility provides service. The ASC so determined will be in effect during the Exchange Period and will apply to the amount of exchange power acquired by Bonneville from the Utility during the Exchange Period. The amount of exchange power will be equal to the Utility's eligible load within the Jurisdiction. Bonneville will determine and pay a separate ASC for the exchange power related to the Utility's eligible load in each Jurisdiction. The procedures are as follows:

A. Appendix 1 is a form that identifies Contract System Costs and Contract System Load and permits the calculation of ASC. Appendix 1 is an integral part of this document.

B. For each Exchange Period and for each regional Jurisdiction in which a Utility provides service, the Utility shall complete and file with Bonneville five copies of Appendix 1 as follows:

   1. On or prior to the effective date of the Utility's residential exchange contract the Utility shall file an Appendix 1 reflecting its existing Costs for each Jurisdiction for which it is participating in the exchange. Subject to the provisions of Section IV, the ASC determined from each Appendix 1 shall be the rate applicable to exchange power from that Jurisdiction during the initial Exchange Period.

   2. Thereafter, not later than five working days after filing for a Jurisdictional rate change or otherwise commencing a rate change proceeding, the Utility shall file with Bonneville a preliminary Appendix 1, setting forth the Costs proposed by the Utility. In addition, within five working days from the day a Utility files for a Jurisdictional rate change or otherwise commences a rate change proceeding, the Utility shall deliver to Bonneville all information initially provided to the Commission. The

Utility also will provide to Bonneville within a reasonable period of time any other information reasonably requested by Bonneville.

3. Not later than five working days following the commencement date of a new Exchange Period, the Utility shall file with Bonneville a revised Appendix 1, reflecting its Costs as approved by the Commission. In addition, the Utility shall provide within 20 working days following the commencement date of a new Exchange Period a reconciliation of all differences between the preliminary Appendix 1 and the revised Appendix 1. Subject to the provisions of Section IV, the ASC included in the revised Appendix 1 will be the ASC applicable to exchange power for that Jurisdiction during the Exchange Period; provided, that if a Utility files a revised Appendix 1 after the five-day deadline Bonneville may make the new ASC payable only from the date the revised Appendix 1 was actually included in the revised Appendix 1 will be the ASC applicable to exchange power for that Jurisdiction during the Exchange Period; provided, that if a Utility files a revised Appendix 1 after the five-day deadline Bonneville may make the new ASC payable only from the date the revised Appendix 1 was actually filed. However, Bonneville shall not delay as a result of a late filing of an Appendix 1 the effective date of any change in the ASC for power provided to it under this agreement if the late filing was the result of unavoidable delay or excusable neglect, and the Utility proceeded to correct the filing error in good faith and with diligence.

C. If Bonneville or any of its Regional Power Sales Customers have been denied the right to participate in a Jurisdictional rate review proceeding on the basis of standing as an intervenor or otherwise with rights equivalent to any retail customer of the Utility, no change in ASC based on a change of Costs authorized in that proceeding shall be effective until Bonneville has completed its review pursuant to Section IV.

IV. Bonneville Review Process

A. Each Appendix 1 shall be reviewed by Bonneville or its designate to determine whether the Costs are not inconsistent with generally accepted accounting principles for electric utilities, whether Contract System Costs contains only allowed Costs, and whether the Appendix 1 complies with the requirements of this Exhibit C including applicable definitions and requirements incorporated from the FERC Uniform System of Accounts. If a retail rate change is authorized without substantive Commission findings as to Costs or if Bonneville or any of its Regional Power Sales Customers are denied the right to participate in a Jurisdictional rate review proceeding on the basis of standing as an intervenor or otherwise with rights equivalent to any retail customer of the Utility, the review by Bonneville or its designate also may consider whether Contract System Costs have changed by the amount of the retail rate change, and Bonneville shall not be obligated to pay an ASC different than the ASC based on Contract System Costs as determined by Bonneville.

B. The Appendix 1 described in Section III(B)(1) shall be subject to review for a period of 180 days following the effective date of the contract. A revised Appendix 1 described in

Section III(B)(2) and (3) shall be subject to review for a period of 120 days from the start of the relevant Exchange Period.

C. Bonneville or its designate will conduct its review as promptly as reasonably possible, shall make a written report of its determinations, and shall make any resulting increase or decrease in the ASC for the relevant Exchange Period; provided, that if Bonneville has not issued a report as of the last date of the review period, then the ASC rate shown on the revised Appendix 1 described in Section III(B)(3) filed by the Utility shall be the ASC for the Exchange Period.

D. Bonneville will afford its Regional Power Sales Customers and other interested persons an opportunity to comment in writing on each Appendix 1 filed by a Utility. To facilitate this process, a Utility filing an Appendix 1 shall mail written notice thereof to each of Bonneville's Regional Power Sales Customers or their designates, in accordance with a list provided by Bonneville. This notice shall summarize the adjustment to costs proposed, make reference to the customers' right to comment thereon, and specify where materials relevant to the Cost adjustment process may be examined. The Utility and Bonneville shall permit Regional Power Sales Customers and interested parties to examine each Appendix 1 submitted to Bonneville. The utilities shall respond to reasonable information requests relevant[**] to ASC from Bonneville and its Regional Power Sales Customers, provided that the furnishing of proprietary or confidential information to Bonneville or to a Regional Power Sales Customer may be made contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. All comments from Bonneville's Power Sales Customers and interested parties must be received in writing by Bonneville no later than 20 days prior to the end of Bonneville's review period. All such comments will be included as part of the record supporting the ASC determined by Bonneville.

E. If Bonneville determines that the ASC computed by the Utility in Appendix 1 was excessive or inadequate, the injured party shall recover the excess or deficiency with interest which shall be computed from time to time on the outstanding balance at the rate or rates of interest charged to Bonneville by the U.S. Treasury during the period unless another form of refund is ordered by the Joint State Board, the FERC, or a reviewing court. If a final order of the Joint State Board, the FERC or a reviewing court revises Bonneville's ASC determination, the difference between this revised ASC and the ASC determined by Bonneville, together with the interest at the above rate, shall be paid to the party entitled thereto by the other party, unless another interest rate is so ordered.

F. If costs associated with a generating facility are included in ASC and that generating facility is later terminated prior to the date of initial commercial operation, Bonneville shall be entitled to recover revenues as follows.

For any exchange period in which Construction Work in Progress (CWIP) was included in the rate base:

1. If the CWIP included in the rate base was identified with a particular generating facility terminated prior to the date of initial commercial operation, Bonneville shall recover revenue based on the amount of CWIP identified with that terminated facility that was included in the ASC rate base.

2. If the terminated facility was among a group of facilities for which CWIP was allowed in the ASC rate base, Bonneville shall recover revenues based on the amount that the CWIP included in the ASC rate base exceeded the utility's total available jurisdictional CWIP for the same group of facilities, after exclusion of any CWIP for generating facilities subsequently terminated prior to the date of initial commercial operation.

When a generating plant is terminated prior to the date of initial commercial operation, the Utility will submit to Bonneville a calculation of the recoverable revenue attributable to the inclusion of the amount of NIP specified above, if any, for each exchange period, including a reconciliation with the final Appendix I for that period. This calculation shall include the effect of any inclusion of Allowance For Funds During Construction (AFUDC) as an offset to test year revenue requirement and the impact on related taxes. The interest rate on revenue to be recovered shall be calculated as in Section IV(E). Bonneville shall bill the Utility in equal monthly installments over a period of the same length as the period during which costs of the terminated facility were included in ASC unless another arrangement is mutually agreed upon.

V. FERC Procedure (Applicable Only to Utilities Subject to Part II of the Federal Power Act)

A. Each Utility that is subject to the FEW s jurisdiction under Part II of the Federal Power Act shall file Bonneville's written report, the ASC determined by Bonneville, and the Utility's Appendix 1 with the FERC, its delegate or successor, within 15 working days of Bonneville's determination of ASC according to Section IV(C) above. During the period between the date of Bonneville's determination of ASC and the date of the final order issued by the FERC, its delegate or successor, the ASC determined by Bonneville shall be in effect.

This filing with the FERC shall be deemed to be compliance by the Utility with Section 205(c) of the Federal Power Act. The ASC ordered by the FERC, its delegate or successor, shall be the lawful ASC in effect from the start of the relevant Exchange Period, and the FERC shall be deemed to have so ordered under Section 205(d) of the Federal Power Act. The Utility may contest any ASC adjustment made by Bonneville in any ASC review proceeding before the FERC, its delegate or successor, and may argue for an ASC to be effective from the start of the relevant Exchange Period calculated pursuant t to the Appendix I described in Section III(B)(3) it filed with Bonneville.

B. The Utility shall notify all parties that made comment to Bonneville on the utility's Appendix I of its ASC filing with the FERC. The FERC shall publish notice of the filing in the Federal Register. The notice shall specify that parties will be allowed an opportunity to comment in writing and to respond in writing to comments filed by any other party. If one or more members of the FERC, its delegate or successor, determine that a substantial issue of fact or law exists, an opportunity for oral presentation of arguments shall be provided.

C. The FERC's review of ASC shall ascertain whether Bonneville's ASC was determined in accord with the methodology described in this Exhibit C. If the FERC, its delegate or successor, should determine that Bonneville's ASC rate was not determined in accord with the methodology, it shall order that such ASC be changed, specifying in the order the necessary changes. The FERC shall publish its final order approving or disapproving the ASC in the Federal Register.

VI Change in Average System Cost Methodology

The Administrator, at his or her discretion, or upon written request from three-quarters of the utilities who are parties to contracts pursuant to section 5(c) of the Regional Act, or from three-quarters of his preference customers, or from three-quarters of Bonneville's direct-service industry customers, shall initiate a consultation process as provided for in section 5(c) of the Regional Act. After completion of this process, the Administrator may propose a new ASC methodology, provided that any consultation process may not be initiated sooner than 1 year after the immediately previous ASC methodology has been adopted by Bonneville and approved by the FERC.

Average System Cost Methodology Instructions

Exhibit C - Appendix I is the form on which a Utility participating in a Residential Purchase and Sale Agreement shall report its Contract System Costs and other necessary data for the calculation of ASC.

The form consists of six schedules that shall be completed by the Utility in accord with these instructions and the provisions of the footnotes following the schedules. Any items not applicable to the Utility shall be so identified.

The schedules are as follows:

Schedule 1 - Plant Investment/Rate Base/Rate-of-Return
2 - Capital Structure and Cost of Capital
3 - Expenses
4 - Income Taxes
5 - Average System Cost
6 - Total Utility and Jurisdictional Results of Operations

The filing Utility shall reference and attach workpapers that support Costs, including details of allocation and functionalization.

All references to the FERC accounts are to the FERC Uniform System of Accounts as of October 1, 1981. The Costs includable in the attached schedules are those includable by reason of the definitions in the FERC accounts. If the FERC accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent that Bonneville, upon a showing of good cause, demonstrates that a particular change results in a substantial change in the type of Costs allowable for exchange purposes. If the Utility does not follow the FERC accounts, its filing must include a reconciliation between its accounts and the items allowed as Contract System Costs.

Bonneville may require the Utility to account for purchase power 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 Jurisdiction shall allocate its total system costs among Jurisdictions in accord with the same allocation methods and procedures used by the Commission to establish jurisdictional Costs and resulting revenue requirements. Appendix 1 shall include details of the allocation. This allocation also accomplishes the exclusion of the Costs of additional resources to meet loads outside the region, as required by section 5(c)(7) of the Regional 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.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Plant Investment/Rate Base/Rate-of-Return
Jurisdiction - _______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Plant-in-Service/310-373 1/ 7/ 8/							
2	General Plant/389-399 2/							
3	Intangible Plant/301-303 3/							
4	CWIP/107, 120.1 3/							
5	Acquisition Adjustment/114 1/							
6	Total Gross Plant							
7	Less:							
8	PIS Depreciation Reserve/108 1/ 4/							
9	General Plant Depreciation Reserve/108 4/							
10	Accumulated Amortization/111, 115 4/							
11	Total Plant Deductions							
12	Total Net Plant							
13	Plant Held for Future Use/105 3/							
14	Nuclear Fuel/120.2-120.4 Less 120.5 1/							
15	Accumulated Deferred Debits/186 3/							

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Plant Investment/Rate Base/Rate-of-Return
Jurisdiction - ______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization: Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
16	Less:							
17	Customer Advances/252 19/							
18	Accumulated Deferred Investment Tax Credits/255 3/							
19	Accumulated Deferred Income Taxes/281-283 3/							
20	Other Accumulated Deferred Credits/253, 256-257 3/							
21	Total Net Accumulated Deferred Debits/Credits							
22	Cash Working Capital/Various 6/							
23	Materials and Supplies/151-157, 163 3/							
24	Other/106, 124, 184, Various 3/ 20/							
25	Total Rate Base							
26	Times Rate-of-Return @ ______% 16/ 23/							

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Rate Base Summary
Jurisdiction - _______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization: Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Utility Plant-in-Service							
2	Less: Accumulated Provision for Depreciation and Amortization							
3	Net Utility Plant-in-Service							
4	Construction Work in Progress							
5	Plant Held for Future Use							
6	Utility Plant Acquisition Adjustments							
7	Nuclear Fuel							
8	Customer Advances for Construction							
9	Materials and Supplies							
10	Cash Working Capital							
11	Unamortized Leasehold Improvements and Other Miscellaneous Deferred Items							
12	Weatherization-Interest Free Loans							
13	Extraordinary Property Losses							
14	Total Rate Base							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 1 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Plant-In-Service
Jurisdiction - _______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Intangible Plant							
	Production Plant:							
2	Steam Production Plant							
3	Nuclear Production Plant							
4	Hydraulic Production Plant							
5	Other Production Plant							
6	Total Production Plant							
7	Transmission Plant							
8	Distribution Plant							
9	General Plant							
10	Total Electric Plant-in-Service							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 1 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Reserve for Depreciation and Amortization of Electric Plant-in-Service
Jurisdiction - ______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Functionalization Total for Transmission	Functionalization Exchange	Functionalization Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Depreciation Reserve							
	Production Plant:							
1	Steam Production							
2	Nuclear Production							
3	Hydraulic Production							
4	Other Production							
5	Transmission							
6	Distribution							
7	General							
8	Total Depreciation Reserve							
9	Amortization Reserve							
10	Total Depreciation and Amortization Reserve							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 1 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Capital Structure and Cost of Capital
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 2

Line No.	Items/Footnotes	Amount	Ratio	Component Cost	Weighted Cost
	(1)	(2)	(3)	(4)	(5)
1	Debt				
2	Preferred Stock				
3	Common Equity				
4	Deferred Income Taxes 10/				
5	Deferred Investment Tax Credit 10/				
6	Total Weighted Cost				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Debt Summary 11/
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 2A

Line No.	Items	Date of Issue	Date of Maturity	Interest Rate	Face Amount	Premium	Discount	Issue Expense	Net Proceeds	Interest Expense
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Preferred Stock Summary
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 2B

Line No.	Items	Shares Issued	Dividend Rate	Outstanding Balance	Premium	Issue Expense	Net Proceeds	Dividends
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								

Exhibit C
Appendix 1
Schedule 3

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Expenses
Jurisdiction - _______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization			
					Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Production:							
2	Fuel/501, 518, 547 1/							
3	Purchased Power/555 1/							
4	Other/500, 502-517, 519-546, 548-577 1/							
5	Transmission/560-573 1/ 4/							
6	Distribution/580-598 1/ 4/							
7	Customer Accounting/901-905 19/							
8	Customer Assistance/907-910 21/							
9	Admin. & General/920-932 12/							
10	Total Operations & Main.							
11	Depreciation & Amortization/403-407 1/ 4/							
12	Taxes Other than Federal Income/ 408, 409.1 3/ 4/ 13/ 14/							
13	Federal Income Tax/409.1, 410.1, 411.1, 411.4 9/							
14	Other/411.6, 411.7 3/							
15	Less:							
16	Nonfirm Sales for Resale Rev./447 22/							
17	Other Operating Rev./450-456 3/ 25/							
18	Billing Credits 5/							
19	Total Operating Expenses							
20	Return from Schedule 1							
21	Less Subsidiary Income							
22	Total Cost 18/							

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Operating Expenses
Jurisdiction - _______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	POWER PRODUCTION EXPENSES							
	Steam Power Generation:							
1	Operation							
2	Fuel							
3	Other							
4	Maintenance							
5	Total Steam Power Generation							
	Nuclear Power Generation:							
6	Operation							
7	Fuel							
8	Other							
9	Maintenance							
10	Miscellaneous Nuclear Research							
11	Total Nuclear Power Generation							
	Hydraulic Power Generation:							
12	Operation							
13	Maintenance							
14	Total Hydraulic Power Generation							
	Other Power Generation:							
15	Operation							
16	Maintenance							
17	Total Other Power Generation							

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Operating Expenses
Jurisdiction - ______________

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Other Power Supply Expenses:							
18	Purchased Power							
19	Other							
20	Total Other Power Supply Expenses							
21	Total Power Production Expenses							
	TRANSMISSION EXPENSES							
22	Operation							
23	Wheeling							
24	Other							
25	Maintenance							
26	Total Transmission** Expenses							
	DISTRIBUTION EXPENSES							
27	Operation							
28	Maintenance							
29	Total Distribution Expenses							
30	CUSTOMER ACCOUNTS EXPENSES							
31	CUSTOMER SERVICE AND INFORMATION EXPENSES:							
	ADMINISTRATIVE AND GENERAL EXPENSES							
32	Operation							
33	Maintenance							
34	Total Administrative and Generation Expenses							
35	TOTAL ELECTRIC OPERATING EXPENES							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 3 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Depreciation and Amortization Accrual
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 3B

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Depreciation:							
1	Steam Production Plant							
2	Nuclear Production Plant							
3	Hydraulic Production Plant							
4	Other Production Plant							
5	Transmission Plant							
6	Distribution Plant							
7	General Plant							
8	Total Depreciation							
9	Amortization of Limited-Term Plant							
10	Amortization of Utility Plant Acquisition Adjustments							
11	Amortization of Property Losses							
12	Total Depreciation and Amortization Accrual							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 3 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Taxes Other Than Federal Income Taxes
Jurisdiction - ______________

Exhibit C
Appendix 1
Schedule 3C

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	FEDERAL - Insurance Contributions							
2	- Unemployment							
	STATE							
3	California - Property							
4	- Unemployment							
5	Oregon - Property							
6	- Tri-Met							
7	- Lane County							
8	- Unemployment							
9	- Regulatory Commission							
10	Washington - Property							
11	- Unemployment							
12	- Generating Tax							
13	- Pollution Control Credit							
14	Idaho - Property							
15	Montana - Property							
16	- Unemployment							
17	Wyoming - Property							
18	- Unemployment							
19	Utah - Property							
20	LOCAL - Occupation and Franchise							
21	STATE INCOME TAXES							
22	IN-LIEU TAXES							
23	OTHER							
24	TOTAL							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 3 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Income Taxes
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 4

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Federal Income Taxes							
2	Deferred Income Taxes							
3	Income Taxes Deferred in Prior Years							
4	Investment Tax Credit Adjustment							
5	Total Federal Taxes							

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Federal Taxes on Income
Jurisdiction - ______________

Exhibit C
Appendix 1
Schedule 4A

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization			
					Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INCOME							
1	Operating Revenues							
	Deductions							
2	Operating and Maintenance Expense							
3	Depreciation Expense							
4	Amortization Expense							
5	Taxes Other Than Federal Income Taxes							
6	Interest Expense							
7	Total Deductions							
8	Net Income Before Federal Income Tax							
	TAX ADJUSTMENTS							
9	Book Depreciation							
10	Tax Depreciation							
11	Charges to Construction							
12	Coal Depletion							
13	Other Adjustments							
14	Total Tax Adjustments							
15	Taxable Income							
16	Preferred Dividends Paid - Credit							
17	Total Taxable Income							
	1.							
	2.							
18	Federal Income Tax							
19	Less Investment Credit							
20	Net Federal Income Tax							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 4 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Other Included Items
Jurisdiction - ______________

Exhibit C
Appendix 1
Schedule 4B

Line No.	Items/FERC Accounts/Footnotes	Jurisdiction Total	Excluded Amount 15b & c/	Total To Be Functionalized	Functionalization Production	Total for Transmission	Exchange	Other
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Operating Revenues:							
1	Nonfirm Sale for Resale/447							
2	1.							
3	2.							
4	3.							
	Other Operating Revenues/450-456							
5	Acct. 450							
6	Acct. 451							
7	Acct. 452							
8	Acct. 453							
9	Acct. 454							
10	Acct. 455							
11	Acct. 456							
12	Total Revenues							
	Other Items:							
13	Investment Tax Credit Adjustment/411.5							
14	Deferred Current Year							
15	Restored Current Year							
16	Restored from Prior Years							
17	Total ITC Adjustment							
18	Deferred Income Tax - Current/410.1							
19	Deferred Income Tax from prior years/411.1							
20	Other Accounts							

Note: 1. Supporting workpapers are to be attached.
2. Footnotes referenced on Schedule 4 will be relied upon in determining ASC.

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Average System Cost
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 5

Line No.	Items	Amount
1	Contract System Costs:	
2	Production Cost (from Schedule 3)	
3	Transmission Cost (from Schedule 3)	
4	Total Contract System Costs	
5	Contract System Load:	
6	Total Load (MWh)	
7	Less:	
8	Nonfirm Adjustment (MWh)	
9	Other Adjustments (MWh)	
10	Net Load (MWh)	
11	Plus:	
12	Distribution Losses (MWh) 17/	
13	Total Net Load (MWh)	
14	Less:	
15	Excluded Load (MWh)	
16	Excluded Load Distribution Losses (MWh)	
17	Total Contract System Load (MWh)	
18	Average System Cost (mills/kWh) (Line 4 ÷ Line 17)	

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Plant-In-Service
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 6A

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
1	Intangible Plant			
	Production Plant:			
2	Steam Production Plant			
3	Nuclear Production Plant			
4	Hydraulic Production Plant			
5	Other Production Plant			
6	Total Production Plant			
7	Transmission Plant			
8	Distribution Plant			
9	General Plant			
10	Total Electric Plant-in-Service			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Reserve for Depreciation and Amortization of Electric Plant-In-Service
Jurisdiction - ______________

Exhibit C
Appendix 1
Schedule 6B

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
	Depreciation Reserve			
	Production Plant:			
1	Steam Production			
2	Nuclear Production			
3	Hydraulic Production			
4	Other Production			
5	Transmission			
6	Distribution			
7	General			
8	Total Depreciation Reserve			
9	Amortization Reserve			
10	Total Depreciation and Amortization Reserve			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Rate Base Summary
Jurisdiction - ______________

Exhibit C
Appendix 1
Schedule 6C

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
1	Utility Plant-in-Service			
2	Less: Accumulated Provision for Depreciation and Amortization			
3	Net Utility Plant-in-Service			
4	Construction Work in Progress			
5	Plant Held for Future Use			
6	Utility Plant Acquisition Adjustments			
7	Nuclear Fuel			
8	Customer Advances for Construction			
9	Materials and Supplies			
10	Cash Working Capital			
11	Unamortized Leasehold Improvements and Other Miscellaneous Deferred Items			
12	Weatherization-Interest Free Loans			
13	Extraordinary Property Losses			
14	Total Rate Base			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Operating Expenses
Jurisdiction - _______________

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
	POWER PRODUCTION EXPENSES			
	Steam Power Generation:			
1	Operation			
2	Fuel			
3	Other			
4	Maintenance			
5	Total Steam Power Generation			
	Nuclear Power Generation:			
6	Operation			
7	Fuel			
8	Other			
9	Maintenance			
10	Miscellaneous Nuclear Research			
11	Total Nuclear Power Generation			
	Hydraulic Power Generation:			
12	Operation			
13	Maintenance			
14	Total Hydraulic Power Generation			
	Other Power Generation:			
15	Operation			
16	Maintenance			
17	Total Other Power Generation			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Electric Operating Expenses
Jurisdiction - _______________

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
	Other Power Supply Expenses:			
18	Purchased Power			
19	Other			
20	Total Other Power Supply Expenses			
21	Total Power Production Expenses			
	TRANSMISSION EXPENSES			
22	Operation			
23	Wheeling			
24	Other			
25	Maintenance			
26	Total Transmission** Expenses			
	DISTRIBUTION EXPENSES			
27	Operation			
28	Maintenance			
29	Total Distribution Expenses			
30	CUSTOMER ACCOUNTS EXPENSES			
31	CUSTOMER SERVICE AND INFORMATION EXPENSES:			
	ADMINISTRATIVE AND GENERAL EXPENSES			
32	Operation			
33	Maintenance			
34	Total Administrative and Generation Expenses			
35	TOTAL ELECTRIC OPERATING EXPENES			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Depreciation and Amortization Accrual
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 6E

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
1	Depreciation:			
2	Steam Production Plant			
3	Nuclear Production Plant			
4	Hydraulic Production Plant			
5	Other Production Plant			
6	Transmission Plant			
7	Distribution Plant			
8	General Plant			
9	Total Depreciation			
10	Amortization of Limited-Term Plant			
11	Amortization of Utility Plant Acquisition Adjustments			
12	Amortization of Property Losses			
13	Total Depreciation and Amortization Accrual			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Taxes Other Than Federal Income Taxes
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 6F

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
1	FEDERAL - Insurance Contributions			
2	- Unemployment			
	STATE			
3	California - Property			
4	- Unemployment			
5	Oregon - Property			
6	- Tri-Met			
7	- Lane County			
8	- Unemployment			
9	- Regulatory Commission			
10	Washington - Property			
11	- Unemployment			
12	- Generating Tax			
13	- Pollution Control Credit			
14	Idaho - Property			
15	Montana - Property			
16	- Unemployment			
17	Wyoming - Property			
18	- Unemployment			
19	Utah - Property			
20	LOCAL - Occupation and Franchise			
21	STATE INCOME TAXES			
22	IN-LIEU TAXES			
23	TOTAL			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Federal Taxes on Income
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 6G

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
	INCOME			
1	Operating Revenues			
	Deductions			
2	Operating and Maintenance Expense			
3	Depreciation Expense			
4	Amortization Expense			
5	Taxes Other Than Federal Income Taxes			
6	Interest Expense			
7	Total Deductions			
8	Net Income Before Federal Income Tax			
	TAX ADJUSTMENTS			
9	Book Depreciation			
10	Tax Depreciation			
11	Charges to Construction			
12	Coal Depletion			
13	Other Adjustments			
	1.			
	2.			
	.			
14	Total Tax Adjustments			
15	Taxable Income			
16	Preferred Dividends Paid - Credit			
17	Total Taxable Income			
18	Federal Income Tax			
19	Less Investment Credit			
20	Net Federal Income Tax			

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Other Included Items
Jurisdiction - _______________

Exhibit C
Appendix 1
Schedule 6H

Line No.	Items	Total Utility	Allocation Basis 15a/	Jurisdictional Amount
	(1)	(2)	(3)	(4)
1	Operating Revenues:			
2	Nonfirm Sale for Resale/447			
3	1.			
4	2.			
5	3.			
6	Other Operating Revenues/450-456			
7	Acct. 450			
8	Acct. 451			
9	Acct. 452			
10	Acct. 453			
11	Acct. 454			
12	Acct. 455			
13	Acct. 456			
14	Total Revenues			
15	Other Items:			
16	Investment Tax Credit Adjustment/411.5			
17	Deferred Current Year			
18	Restored Current Year			
19	Restored from Prior Years			
20	Total ITC Adjustment			
21	Deferred Income Tax - Current/410.1			
22	Deferred Income Tax from prior years/411.1			
23	Other Accounts			

Average System Cost Methodology Footnotes

1/ Functionalized directly from the FERC Uniform System of Accounts.

2/ Unless it can be determined that a plant item or plant related item is associated directly with regional generation, transmission, distribution, customer or other directly functionalized category, item shall be functionalized on the following basis in the following order:

(a) If the location codes of the plant item can be used to identify a principal generation, transmission, distribution or customer-related facility at that location, the plant item shall be functionalized based on the functionalization of such principal facility.

(b) For plant items not otherwise functionalized, the functionalization formula in footnote 24 shall apply.

3/ (a) The utility shall functionalize these items according to an analysis it performs that demonstrates the actual and/or intended functional use of the items, or the plant item related thereto, and include a detailed showing of the factors used to determine the functionalization as a supplement to Exhibit C, Appendix 1. Costs incurred only because the utility is engaged in the retail distribution of electricity shall be functionalized to Other. These items include, for example, retail revenue taxes and uncollectible amounts for retail sales.

(b) In cases where items included are not directly assigned to a particular function, these items shall be separately identified, and a statement shall be provided as to why the items are not directly functionalized by the 3(a) procedure. The functionalization formula described in footnote 24 herein shall apply to these items.

4/ Calculation of functionalized amount is to be consistent with property items included in functionalized Total Gross plant.

5/ The offset against Contract System Costs for billing credit revenue arising from implementation of conservation measures and retail rate structures that induce conservation shall be limited to the costs included in Contract System Cost of the related conservation measures and retail rate structures. These billing credit revenues shall be functionalized on the same basis as the cost of the related conservation measure

6/ Functionalization is to be directly related to the functional nature of the items included in the Working Capital calculation approved by the Commission. Should items included in the approved Working Capital calculation not be directly assignable to a function and should there be no footnote in this methodology directing the functionalization of the item, these items shall be separately identified and the functionalization formula in footnote 24 shall apply.

7/ Transmission plant means all land, conversion structures, and equipment employed at a primary source of supply (*i.e.*, generating station or point of receipt in the case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; all land, structures, lines, switching and conversion stations, high tension apparatus and their control in protection of equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and all lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply. The entrance to a distribution center means all land, structures, conversion equipment, lines, line transformers and other facilities utilized to deliver power to specific customers or distribution substations.

8/ Distribution plant means all land, structures, conversion equipment, lines, line transformers, and other facilities employed between the primary source of supply (*i.e.*, generating station, or point of receipt in the case of purchased power) and of delivery to customer, which are not includable in transmission system, as defined in footnote 7, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system.

Note: Stations that change electricity from transmission to distribution voltage shall be classified as distribution stations.

Where poles or towers support both transmission and distribution conductors, the poles, towers, anchors, guys, and rights-of-way shall be classified as transmission system. The conductors, crossarms, braces, grounds, tiewire, insulators, *etc.*, shall be classified as transmission or distribution facilities, according to the purpose for which they are used.

Where underground conduit contains both transmission and distribution conductors, the underground conduit and right-of-way shall be classified as distribution facilities. The conductors shall be classified as transmission or distribution facilities according to the purpose for which they are used.

Land (other than rights-of-way) and structures used jointly for transmission and distribution purposes shall be classified as transmission or distribution according to their major use.

9/ Functionalized as specified in Schedule 4.

10/ If these items are treated in Schedule 1 as deductions from gross plant investment in determining rate base, these items shall not be included in the capital structure.

11/ Should a Commission approve a method for determining debt costs by a means other than that shown here, Schedule 2A shall be modified in a manner that shows the approved method, including accompanying explanatory material.

12/ Expenses related to the FERC Accounts 920-932 shall be functionalized in accord with the following:

FERC Account	Functionalization Method
920	Footnote 3
921	3
922	3
923	3
924	3(a) or 24(a)
925	3
926	13
927	19
928	19
929	3
930.1	19
930.2	3
931	19
932	4

13/ Functionalization is to be determined on a pro rata percentage basis using the salary and wage data for production, transmission, and distribution/other functions included in the Test Period costs on which Appendix 1 is based. If, however, this information is unavailable, comparable data shall be used for the most recent calendar year as reported on the FERC Form 1 (at page 355), or similar document. Furthermore, a portion of this expense shall be included in Schedule 3, column 3, Excluded Amount, based on the amount of labor-related costs included therein.

14/ 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 but in no event shall the jurisdictional total in column 2 be greater than the actual amount paid.

15/ Excluded Resources

(a) The cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980, will be determined by utilizing allocation notes of multi-State utilities as assigned and utilized in State rate filings.

(b) The cost of additional resources sufficient to serve any New Large Single Load 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 New Large Single Loads are served by dedicated resources, at the cost of those resources, including applicable transmission;

(2) In the amount that New Large Single Loads are not served by dedicated resources, at Bonneville's New Resource rate as established from time to time pursuant to section 7(f) of the Regional Act and as applicable to the Utility, and applicable Bonneville transmission charges if transmission costs are excluded in the determination of

Bonneville's New Resource rates, to the extent such costs are recovered by the Utility's retail rates in the applicable jurisdiction; and

(3) To the extent that New Large Single Loads are not served by dedicated resources plus the Utility's purchases at the New Resource rate, the costs of such excess load shall be determined by multiplying the kilowatthours 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 kilowatthour of all baseload 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 New Resources rate pursuant to section 7(f) of the Act; (b) purchases at the Federal Base System rate, pursuant to section 5(c) of the Act; (c) resources sold to Bonneville, pursuant to section 6(c)(1) of the Act; (d) dedicated resources specified in footnote 15(b)(1) of this agreement; (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 for the Jurisdiction during the Exchange Period.

(4) Any kilowatthours of New Large Single Loads not met under subsections (1), (2), or (3) above will be assumed to be supplied from the most recently completed or acquired baseload resource(s) or long term power purchase(s), exclusive of dedicated resources and experimental or demonstration resources or purchases therefrom, that are committed to the Utility's load as of September 1, 1979, under a power requirements contract with Bonneville or would have been so committed had the Utility entered into such a power requirements contract. The cost of these generation resources and long-term power purchases and the transmission cost associated with these resources or purchases will be calculated as specified in subsection (3) above.

(5) If the New Large Single Load is served on an energy or capacity interruptible basis, the Utility shall prepare a calculation subject to review by Bonneville of the fixed (if any) and variable costs of providing such service, except that the amount excluded from ASC for the New large Single Load shall not be less than the transmission and generation costs included in the retail rate charged the New Large Single Load.

(c) Any costs associated with a generation facility that is terminated prior to initial commercial operation shall be excluded if termination occurred after December 5, 1980.

16/ Authorized Jurisdictional rate of return as specified in Schedule 2.

17/ 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 used by the Commission for the purpose of establishing retail rates. Losses shall be established according to a study (engineering, statistical or other) that is submitted to Bonneville by the exchanging Utility subject to review by Bonneville. 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.

18/ This amount is to be reduced by revenues from firm sales for resale (to the extent that these sales are included in the Jurisdictional allocation factors) to be determined by the firm resale revenue for the Test Period as used for retail ratemaking purposes.

19/ Functionalize entirely to distribution/other unless Utility demonstrates that other functionalization treatment is appropriate.

20/ "Other" rate base items may include Unclassified Plant-In-Service (106), Extraordinary Property Losses (182), Other Investments (124), or other investments approved for rate base treatment by a Commission consistent with the provisions of this Exhibit.

21/ Only the conservation-related portion is to be functionalized to production.

22/ These revenues shall be divided proportionally between Excluded Amount and Total To Be Functionalized based on the total expenses in those two categories shown on Schedule 3 (sum of lines 1 to 13, 19, and 20), less all terminated plant expenses excluded pursuant to footnote 15(c). The portion to be functionalized shall be functionalized to production.

23/ Public Agencies shall be allowed a total return (operating income) on Schedule 1, line 26, column 2, equal to their demonstrated need for revenues exceeding Total Operating Expenses shown on Schedule 3 to cover the cost of capital. These demonstrated capital costs generally will be in the form of coverage requirements or the need to maintain an equity ratio consistent with favorable bond ratings for that Utility. In order to receive an operating income in addition to interest expense, the utility must submit evidence of the specific coverage or equity ratio needed by that utility and a calculation of the corresponding minimum operating income. Assignment to excluded resources and functionalization of the operating income shall be on the assignment and functionalization of the rate base.

24/ Functionalization of these items shall be based on a formula that averages on an equal weighting basis the percentages for generation, transmission, distribution, and customer-related functions for (a) the gross plant in each function, including general plant and other plant items functionalized in step 1 of footnote 2 and, (b) the functionalized operations and maintenance (O&M) expenses shown in Schedule 3, except that the fuel cost included in O&M shall not include the cost of fuel acquired from non-Utility sources. Material detailing the application of this functionalization formula shall be included as a supplement to Appendix 1.

25/ Revenues from the transmission of electricity for others shall be functionalized to transmission.