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AVERAGE SYSTEM COST METHODOLOGY

ADMINISTRATOR'S RECORD OF DECISION

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

June 1984

1984 AVERAGE SYSTEM COST
METHODOLOGY PROPOSAL
(BPA File No. ASC-83)

BONNEVILLE POWER ADMINISTRATION
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ADMINISTRATOR'S RECORD OF DECISION

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INTRODUCTION

This Record of Decision culminates the statutory consultation proceeding begun last October 7, 1983. 48 Fed. Reg. 45829. A comprehensive record of some 7,000 pages has been compiled through public comments, hearings and negotiation sessions. The record has been of considerable utility in probing the arguments of interested parties on the determination of a methodology for calculating the average system cost of resources (ASC) which sets the residential exchange subsidy paid by Bonneville Power Administration (BPA) to certain Pacific Northwest electric utilities.

Significant features of the ASC methodology adopted in this Record of Decision include:

1. Retention of the so-called jurisdictional approach under which retail rate orders of regulatory agencies are used as the primary source of data for computing the ASC for utilities participating in the residential exchange. However, BPA will carry out its statutory role through an independent determination of the validity of all data submitted in ASC filings recognizing the different purposes of ASC filing review and retail rate regulation. This independent determination will require greater involvement in retail rate cases of utilities participating in the residential exchange program.

2. Inclusion of transmission costs in the calculation of ASC, with a review of all future transmission plant additions to ensure that they are not redundant of the existing transmission grid.

3. Exclusion of all Construction Work In Progress from the calculation of ASC.

4. Use of a participating utility's weighted cost of debt securities to determine a return component of ASC. This is intended to eliminate the potential for utilities to recover terminated power plant costs indirectly through their jurisdictionally allowed equity returns and capital structures.

5. Exclusion of income taxes from ASC, meaning that BPA will no longer subsidize the income taxes of participating utilities. Income taxes are not a cost of resources within the meaning of Section 5(c) of the Northwest Power Act.

6. Simplification of procedures for functionalizing (separating) costs between subsidized generation and transmission accounts, and nonsubsidized distribution and "other" accounts.

7. Clarification of Section VI, *Change In Average System Cost Methodology*, of the current ASC Methodology to better reflect the purpose of the rule. Once an ASC Methodology is adopted in a record-building proceeding, the Administrator may retain that methodology for at least one year after implementation so that experience may be gained thereunder before it is subject to further revision or change.

8. Changes in the timetable for BPA review of individual ASC filings to permit more thorough analysis.

9. "Phase-in" of the reformed ASC methodology in order to minimize the retail rate effects of the change in methodology. Under the phase-in, the new methodology would be implemented by the Commission on July 1, 1984, the date on which participating utilities qualify to exchange 90 percent of their residential loads under Section 5(c) of the Northwest Power Act. However, for the ensuing 12-month period, the actual ASC subsidy for each participating utility would be determined as the average of the ASC in effect on July 1, 1984, and the ASC calculated under the new methodology. On July 1, 1985, the new methodology would become the exclusive means of determining the ASC of each participating utility.

10. Each exchanging utility is required to file under the new methodology within 20 days after implementation by the Federal Energy Regulatory Commission. Any utility failing to do so, will have its ASC deemed equal to zero until compliance occurs.

Of the ten major utilities participating in the residential exchange program, the revised ASC methodology will substantially affect only three: Portland General Electric Co., Pacific Power & Light Co., and Utah Power & Light Co. Four of the other seven are presently in a "deeming" *See* page 6, below) status because their existing ASC is less than or equal to BPA's priority firm power rate. Under the revised methodology adopted in this decision, BPA estimates that it will continue to pay a residential exchange subsidy of approximately $170 million per year through the residential exchange program.

CHAPTER ONE

BACKGROUND

A. Relevant Statutory Provisions

Section 5(c)(1) of the Northwest Power Act, 16 U.S.C. §839c(c)(1), provides that BPA shall acquire certain amounts of power offered for sale by Pacific Northwest electric utilities. In exchange, BPA offers to sell "an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.[1] *See, generally*, H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. at 60 (1980). Sales to the utility may not be restricted below the amount of power acquired from the utility. *See* section 5(c)(6).

The residential exchange is not a conventional power transaction. There is no power transferred either to or from BPA.[2] System schedulers do not dispatch the exchange; line losses are not incurred. "In practice, only dollars are exchanged, not electric power." *Public Utility Commissioner of Oregon v. BPA*, Civil No. 84-270-PA, slip op. at 6 (D. Or. March 21, 1984). "In essence, what really happens is [that) BPA writes a check to the utility; no power actually flows back and forth." Comments of Portland City Commissioner Lindberg, R. 716. "You [BPA] pay 150 or 250 million dollars a year, and you don't get any kilowatts or kilowatt hours for it, but you keep paying." Oral comments of Pacific Power & Light Co. (R. 2325).

The power sale concept was created by Congress for BPA ratemaking purposes. *E.g.*, section 7(b)(1).[3] Practically speaking, the purpose of the residential exchange is to provide a subsidy to exchanging utilities. Costs subsidized by BPA do not have to be recovered in the retail rates charged to the residential customers of exchanging utilities.

BPA exchange power is priced at the same rate as that for general requirements sales to preference customers (the "priority firm rate"). *See*, section 7(b)(1) of the Northwest Power Act, 16 U.S.C. §839e(b)(1). In contrast, the amount paid by BPA to the participating utility is not a conventional power rate. Section 5(c)(1) states that BPA is to pay "the average system cost of that utility's resources." 16 U.S.C. §839c(c)(1). Section 5(c)(7) of the Northwest Power Act gives BPA's Administrator the discretionary authority to determine average system cost (ASC) on the basis of the methodology to be established in consultation proceedings. 16 U.S.C. §839c(c)(7). The only express statutory limits on the Administrator's authority are found in section 5(c)(7)(A), (B) and (C),

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[1] The exchange was set equal to 50 percent of a participating utility's qualifying residential and small farm load as of July 1, 1980, and has been increasing in equal increments toward 100 percent of such load. *See*, section 5(c)(2).

[2] Section 5(c)(5) allows BPA to acquire an "equivalent amount of electric power from other sources to replace power sold to [a participating] utility," if the cost of such replacement acquisition is less than the applicable ASC. Once again, however, the key phrase is "equivalent amount." In any event, such alternative purchases, other than BPA resources, have been construed to require seven years advance notice. *See*, section 4(a), Residential Purchase and Sale Agreement, Contract No. DE-MS79-83BP9. BPA designates this contract as part of the record of this consultation proceeding. (R. 6800).

[3] The outcome of this consultation proceeding will not change the way in which BPA establishes rates under section 7 of the Northwest Power Act. The resource concept'was devised by Congress to allocate the benefits and costs of the Federal Base System among competing classes of BPA customers. BPA has faithfully implemented Congress' ratemaking directives. However, the resource concept should not obfuscate the nature of the residential exchange as a subsidy from BPA to the participating utilities.

The residential exchange subsidy, sometimes referred to as "wholesale rate parity" with BPA's wholesale preference customers, was intended to give residential ratepayers of investor-owned utilities a form of access to low-cost Federal hydroelectric resources. Wholesale rate parity was the first attribute of the residential exchange originally intended by Congress.[4]

Under section 5(c) of the Northwest Power Act, wholesale rate parity was to work in two directions. Whenever the BPA priority firm rate is lower than a participating utility's ASC, BPA would pay a subsidy to that utility. However, that exchanging utility could owe an exchange payment to BPA when its ASC was lower than BPA's wholesale preference rate. This symmetry was destroyed by the residential purchase and sale contracts executed by BPA and the utilities participating in the residential exchange. Under the so-called "deemer" clause found in section 10 of these contracts, the exchanging utility has a unilateral right to "deem" its average system cost equal to BPA's preference rate whenever it might otherwise owe money to BPA under the residential exchange.[5] The residential exchange only works to the advantage of participating utilities; it never lowers the rates of BPA customers. Because of the deemer clause, exchanging investor-owned utilities now have the assurance that their resource costs will be equal to, or actually less than, BPA's wholesale preference rate. Instead of creating wholesale rate parity, the deemer provision of residential exchange contracts may actually reverse the rate disparity that Congress sought to eliminate. *See* comments of Public Power Council (May 13, 1983) (R. 84-85).[6]

In section 5(c)(7), Congress provided an express mechanism for formulation of an electric utility's "average system cost" (ASC). Section 5(c)(7) states:

> 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;

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[4] However, Congress has recognized that this wholesale rate parity could last only until July 1, 1985, due to the rate protection accorded BPA's preference customers as of that date. *See* section 7(b)(2) and 7(b)(3), 16 U.S.C. §839e(b)(2) and (b)(3).

[5] However, BPA does keep an account of such unpaid amounts, which are offset against subsequent BPA payments to the utility. *See* section 10, Residential Purchase and Sale Agreement, BPA Contract No. DE-MS79-81BP9.

[6] Furthermore, section 5(c)(4), 16 U.S.C. §839c(c)(4), recognizes that BPA's priority firm rate, insofar as it applies to the residential exchange, may carry one or more "supplemental rate charges" after July 1, 1985, due to implementation of section 7(b)(3) of the Northwest Power Act, 16 U.S.C. §839e(b)(3). Were this to occur and cause the applicable priority firm rate to exceed a participating utility's ASC, that utility 'could terminate its participation in the residential exchange. *See* section 9 of the Residential Purchase and Sale Agreement, *id.*

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

Section 5(c)(7) requires that the ASC subsidy (1) be determined by the Administrator, (2) be based upon a rate formula methodology developed by the Administrator in consultation with the Northwest Power Planning Council, BPA customers, and state regulatory bodies, (3) be subject to review and approval by the Federal Energy Regulatory Commission (FERC), and (4) not include costs identified in section 5(c)(7)(A), (B), and (C).

The ASC methodology established by the BPA Administrator pursuant to section 5(c)(7) of the Northwest Power Act is a "rate formula." *Public Utility Commissioner of Oregon v. BPA*, Civil No. 84-270-PA, slip. op. at 6 (D. Or. March 21, 1984). The methodology is an administrative rule of both BPA and FERC. *See* 18 C.F.R. §35.13a (1983 ed.).

Under the methodology, exchanging utilities make proposed ASC filings with BPA, which reviews the filings for conformity with the ASC methodology and the requirements of section 5 of the Northwest Power Act. The BPA Administrator then determines the appropriate ASC for the filing utility. The utility receives an exchange subsidy according to the ASC determined by the Administrator and approved by FERC.

Through June of 1985, BPA's rates for service to direct-service industrial (DSI) customers are to recover, inter alia, the "net costs incurred by the Administrator pursuant to section 5(c) of this Act … to the extent that such costs are not recovered through rates applicable to other customers." *See*, section 7(c)(1)(A). However, beginning in July of 1985, a new ratemaking methodology for recovering the net cost of the residential exchange is to be established. Then, residential exchange costs may have a greater effect on the rates of all customer classes.

The ASC methodology must be designed so that BPA does not become the "deep pocket" to which participating utilities may shift excessive or improper resource costs. The methodology should give participating utilities an incentive to minimize their costs. Otherwise, BPA could be faced with either of two statutorily impermissible alternatives. First, BPA may not be able to set reasonable rates for its customers, who must pay the cost of the subsidy through their rates. Second, if net exchange costs cause rates to rise to the level where loads decline, BPA may not be able to satisfy the requirement of section 7(a) of the Northwest Power Act that its rates recover total revenue requirement. BPA is a self-financing government agency, which must recover its costs through rates for sales of electric power and energy. *See* 16 U.S.C. §§832f, 838g and 839e(a). The residential exchange subsidy should not be borne by the Federal Treasury.

Consistent with its role in reviewing BPA rates under section 7(a)(2) of the Northwest Power Act, 16 U.S.C. §839e(a)(2), BPA believes that FERC's role in reviewing the ASC methodology is to ensure that subsidy payments do not inhibit BPA's ability to meet its revenue requirement, which includes repaying all Federal Treasury investments in the Columbia River Power and Transmission Systems. Currently, the gross cost of the residential exchange program is the largest single component of BPA's revenue requirement. While the Northwest Power Act and its legislative history are virtually silent on the Commission's substantive role in reviewing the ASC methodology, clearly that role cannot be to increase the level of subsidy paid by an agency of the Federal government to profit-making, investor-owned utilities. Such a role would be antithetical to the traditional review exercised by the FERC over Federal power marketing agencies. FERC should narrowly construe statutes that serve to increase BPA's revenue requirement.

B. The Current Average System Cost Methodology

The first average system cost methodology (1981 methodology) was established pursuant to section 5(c)(7) on August 26, 1981, in an Administrator's Record of Decision. That decision was based on a settlement agreement, which had resolved nearly all issues raised by parties in the consultation proceeding.

The Administrator filed the 1981 methodology with FERC on August 27, 1981. The Commission approved the 1981 methodology, on an interim basis, on October 14, 1981. 46 Fed. Reg. 50,517-538 (1981) (corrected at 46 Fed. Reg. 55,952-954). Final Commission approval was received on October 17, 1983, in an order that made no substantive change to the methodology proposed by BPA. 48 Fed. Reg. 46,970. Total residential exchange subsidies paid under the 1981 ASC methodology are depicted in the following table:

UTILITY	TOTAL SUBSIDY SINCE 1981
Portland General Electric Co.	$163,613,383
Pacific Power & Light Co.	155,667,709
Utah Power & Light Co.	38,705,912
Idaho Power Co.	34,872,411
Puget Sound Power & Light Co.	25,439,382
Washington Water Power Co.	6,030,216
C.P. National Co.	2,810,066
Montana Light & Power Co.	40,055
Montana Power Co.	(120,047)
Publicly Owned Utilities (12)	8,445,075
TOTAL SUBSIDY PAID BY BPA	$435,504,162

Under the 1981 methodology, a preliminary "Appendix 1" must be filed with BPA by each participating utility whenever that utility commences a retail rate change proceeding before a regulatory authority. 1981 Methodology, §III. Appendix 1 is a form that identifies the "Contract System Costs" and "Contract System Load" used in the calculation of ASC. Later, the Appendix 1 is revised when the regulatory authority approves final retail rates. The ASC of each participating utility includes the costs approved by the regulator.

BPA reviews each Appendix 1 for conformance with criteria specified in the 1981 methodology. The first Appendix 1 filed by a utility is subject to review for 180 days following the effective date of its residential exchange contract. Subsequent Appendix l filings are subject to review for 120 days from the start of the relevant exchange period. BPA customers and other interested persons are provided an opportunity to submit comments on each Appendix 1 filed. 1981 Methodology, §IV(D). All such comments are due no later than 20 days prior to the end of

BPA's review period. If BPA has not issued a report by the last date of the review period, then the ASC proposed on the basis of a utility's revised Appendix 1 becomes the ASC for the relevant exchange period.

The ASC filings of exchanging utilities are rates which, in the instance of investor-owned utilities, are also subject to review by FERC under Part II of the Federal Power Act, 16 U.S.C. §.824(a), et seq. *See generally*, "Filing of rate schedules for sales of electric power under the Pacific Northwest Electric Power Planning and Conservation Act," 18 C.F.R. § 35.13a(c)(2). *See* also 16 U.S.C. §839f(g). These regulations define ASC filings as rates, 18 C.F.R. 35.13a(c), and waive Federal Power Act regulations in instances of inconsistency, 18 C.F.R. §35.13a(c)(2). *See Public Utility Commissioner of Oregon v. BPA*, slip op. at 6. Each utility subject to FERC jurisdiction must file BPA's written report, the ASC determined by BPA, and the revised Appendix 1 with FERC within 15 days of BPA's determination. During the period between the date of BPA's determination and the date of the final FERC order, the ASC determined by BPA is used, subject to later refund.

Reliance on state regulatory agencies to determine the level of costs included in the ASC of a participating utility, the "jurisdiction costing approach," has caused several problems of administration for BPA. Routinely, the orders of regulatory agencies do not contain the specific numbers necessary for ASC computation. In such instances, values for ASC accounts must be imputed.

Another drawback to the jurisdictional approach, as it is presently used, is that state rate regulators are not responsible for enforcing the requirements of section 5(c). Instead, they are charged by state law or local ordinance with setting reasonable rates, which maintain the financial health and stability of the regulated utility. The interests of utility ratepayers and shareholders are commonly viewed as antagonistic. The courts have accorded regulators the latitude of a "zone of reasonableness" in which to set rate that balance these interests. *Federal Power Commission v. Natural Gas Pipeline Company*, 317 U.S. 575, 585 (1942). However, the choice of rates within this zone undoubtedly is affected by BPA's obligation under the 1981 methodology to provide whatever subsidy payment a retail rate order dictates.

With a subsidy from BPA in the picture, higher retail rates do not necessarily produce higher bills for residential ratepayers. This phenomenon favors the establishment of retail sales at the upper end of the zone. A participating utility may not be given an adequate incentive to control its costs. Yet, BPA simply cannot intervene and participate in every regional rate proceeding to protect the interests of its own customers and its ability to recover revenue requirement.[7] Also, BPA would not want to influence the ratemaker since the purpose of the action taken by both parties is different.

There have been instances when serious concern has been raised that costs approved for retail ratemaking purposes, and thus added to the residential exchange subsidy under the 1981

[7] BPA does not take issue with the way in which any rate regulator follows the dictates of its governing statute or ordinance. We are not necessarily suggesting that retail residential rates have been set above the zone of reasonableness before application of the BPA exchange subsidy. BPA's problems with the jurisdictional costing approach focus on the dissimilarities between the Northwest Power Act and state regulatory laws and policies.

methodology, have included terminated plant costs prohibited under section 5(c)(7)(C). In one case, terminated plant costs were removed from an ASC filing during BPA review. *See* BPA's Average System Cost Report for Portland General Electric Company, Jurisdiction: Oregon (May 13, 1983). In another case, terminated plant issues were debated but became moot when another adjustment was made by BPA to an ASC filing. *See*, Average System Cost Report for Pacific Power & Light Company, Jurisdiction: Oregon (November 2, 1983).

Terminated plant issues, in particular, caused all BPA's DSI customers to request a change in ASC methodology by invoking section VI of the 1981 methodology. (R. 82, 88). BPA's public agency customers also requested a new consultation proceeding. (R. 83, 84).

CHAPTER TWO

INITIATION OF THE CURRENT CONSULTATION PROCEEDING

A. Procedural History

This proceeding has its antecedents in a BPA review of an ASC filing by Pacific Power & Light Company (PP&L) regarding which it had been alleged that terminated power plant costs had been unlawfully included. After analyzing circumstantial evidence on the issue, BPA concluded that it could not specifically identify any such costs in the filing. Probative data were not available to establish precisely what the Oregon Public Utility Commissioner had done in a cryptic rate order. In the BPA report on PP&L's ASC filing, dated December 27, 1982, BPA noted that:

> BPA has an express duty to comply with Section 5(c)(7)(C) of the Regional Act. This section requires BPA to exclude from Average System Cost any costs of generation facilities that are terminated prior to date of commercial operation. Our review did not identify cost associated with terminated plant in PP&L's rate base, cost of capital, expenses, or the effect of such costs on PP&L'S filed Average System Cost. However, we have concerns. The present Average System Cost Methodology is designed in such a way that the cost of capital, return on equity, and extraordinary gains and losses could conceal terminated plant costs. We think it would be appropriate to revise the Average System Cost Methodology to demonstrate clearly that the requirements of Section 5(c)(7)(C) (16 U.S.C. §839c(c)(7)(C)) are being met. BPA plans to initiate a consultation process to revise the Average System Cost Methodology. (ASC report of December 27, 1982, at 1, FERC Docket No. ER83-266-000.)

BPA's public agency customers took the lead in urging that the 1981 ASC methodology be reformed in a consultation proceeding under section 5(c) of the Northwest Power Act. In a letter of May 13, 1983 (R. 84), the manager of the Public Power Council (PPC), representing 115 BPA preference customers, stated:

> The PPC has a long range stake in Bonneville's fiscal integrity. We share your desire to put Bonneville on better financial footing. It has been a year and a half since the Federal Energy Regulatory Commission (FERC), approved the average system cost (ASC) methodology on an interim basis. In that year and a half Bonneville has seen the cost of the Exchange go from a 1981 estimate of gross exchange cost of $350 million to $500 million to an estimate of 51.05 billion for FY 1985. … In the initial 1983 rate proposal, the Exchange is more than 20 percent of the cost of the priority firm rate. As the Exchange has grown, so too have BPA's deficits ($376 million this year).
>
> The cost of the Exchange is now too great a burden for either the direct service industries or for your preference customers. The ASC methodology has also encouraged "game playing" by some private utilities at the state public utility

> commissions. As Administrator, you have within your power the ability to control the cost of the exchange, both through better enforcement and through a change in the Average System Cost (ASC) methodology. It has been more than a year since FERC approved BPA's proposed methodology. It is time to recognize that the original ASC methodology simply isn't working.
>
> The Exchange has given region's exchanging private utilities far more than the framers of the Regional Power Act ever contemplated. The Exchange was to make cheaper federal generation available to the residential customers of the investor-owned utilities, and thereby achieve parity in the cost of generation. Thanks to the existing ASC methodology, plus the cost of escalation in the Washington Public Power Supply System Plants, the rates of many of the region's consumer-owned utilities are now higher than those of the neighboring investor-owned utilities.
>
> * * *
>
> The past year's experience under the interim methodology has taught us that the methodology is greatly in need of repair. Therefore, we strongly urge you to exercise your right under Section IV [sic] of the ASC methodology to initiate a consultation process to amend the existing methodology.

Similarly, BPA's direct service industrial customers, by letters dated April 13, 1983, and August 16, 1983, stated that "BPA must immediately move to reopen and revise the ASC methodology" (R. 82, 88).

BPA's administrative rules governing the residential exchange subsidy include section VI of the 1981 ASC methodology, which requires the Administrator to initiate a statutory consultation proceeding "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…" 18 C.F.R. §35.13a(d)(6) (1983 ed.).

On October 7, 1983, BPA initiated the present consultation proceeding by publishing a "Request for Recommendations" in the *Federal Register*. 48 Fed. Reg. 45829 (1983). This notice listed 17 issues for comment and encouraged additional comments on issues related to the development of a reformed ASC methodology. Voluminous responses were received by November 7, 1984. (*See* R. 129-442.)

On February 3, 1984, after reviewing the comments received in response to BPA's earlier *Federal Register* notice, BPA published a "Proposed Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange." 49 Fed. Reg. 4230 (1984). The notice stated in part

> The procedures adopted by BPA in this ongoing consultation are intended to facilitate the compilation of a full record on which the Administrator will base this decision. Comments have already been filed by groups including investor-owned utilities, state regulatory agencies, preference customers and DSI

> customers. This notice solicits a new round of initial and reply comments from interested members of the public. After completion of the noticed procedures, which include negotiation of stipulated agreements, the Administrator intends to establish a new improved ASC methodology. The new ASC methodology, accompanied by a Record of Decision, will be submitted for review and approval by FERC.
>
> * * *
>
> After the written comment stage, an opportunity will be provided for oral presentations before the Administrator, which will be transcribed for inclusion in the record. … During any stage of the proceeding, negotiated resolutions of issues, raised by BPA or by commenters, may be incorporated into the record by means or written stipulations.
>
> * * *
>
> It is inevitable that BPA's proposal will not satisfy every commenter. Also, comments will raise other issues that may not have been apparent to BPA. We stress the importance of written comments which precisely state each commenter's position on issues of concern. BPA intends that a complete record be compiled. [49 Fed. Reg. at 4233.]

This notice provided for the filing of comments on the proposal until March 15, 1984, with reply comments due April 9, 1984. These dates were later extended by BPA to March 19 and April 13, 1984, respectively, at the request of BPA's investor-owned utility customers (R. 2936). Extensive written comments and reply comments were filed by all interested parties. (*See* R. 443-185A, 721-853.)

By letter dated February 17, 1984, BPA announced that between February 24 and March 1, 1984, public meetings would be held in Spokane and Seattle, Washington; Portland, Oregon; and Idaho Falls, Idaho, to clarify technical aspects of the proposed methodology. Extensive discussions occurred at these sessions, which were transcribed and included in the record. (*See* R..915-943 (Spokane), R. 975-1062 (Seattle), R. 944-974 (Portland), and R. 1063-1150 (Idaho Falls)).

On March 2, 1984, BPA issued a letter announcing that a public meeting would be held on April 20, 1984 "to discuss all issues relating to the BPA proposal, initial comments, reply comments and possible settlement of any issue" (R. 2936). BPA noted that the meeting would be transcribed, that additional meetings would be scheduled with the Regional Council and State regulatory commissions, and that BPA would consider requests for meetings with smaller groups of parties. Many parties participated in the April 20, 1984, meeting. Representatives of the investor-owned utilities walked out of the meeting, in a public demonstration against BPA's proposed methodology, before all participants had made their presentations. (*See* R. 2938.)

Additional public meetings were held between April 23 and 27, 1984. (R. 1493-2221). These transcribed sessions involved extensive face-to-face negotiations between all the parties present. Additional negotiating sessions were conducted between April 30 and May 4, 1984. (R. 2222-2180). Transcripts of each meeting are included in the record of this proceeding. (R. 1317-2810) BPA's investor-owned utility customers refused to participate in any of these negotiations with BPA staff on resolution of issues pertaining to possible ASC methodologies. Instead, these utilities merely sent an "observer" to these public sessions.

On April 30, 1984, the BPA Administrator heard extensive oral presentations by all interested parties. (R. 2228).

On May 15, 1984, following review of the voluminous record compiled at that time, BPA staff released a new proposed ASC methodology (R. 2945 -2973). The staff proposal summarized the consultation proceeding, the proposal negotiated by interested parties, and a possible phase-in of the new methodology in order to minimize the effect of a methodological change on the retail ratepayers of exchanging utilities. A fourth and final round of public comments was solicited, to be received, by May 25, 1984. (R.2982).

On May 17, 1984, BPA mailed a draft index of the official record to all parties, requesting comments on possible corrections or supplementation. (R. 2974).

This decision determines a new ASC methodology, based on a thorough review of some 7,000 pages of record.

B. The Nature Of Consultation Proceedings Under Section 5(c)

The Northwest Power Act gives the Administrator discretionary authority to determine the ASC of each exchanging utility, based on a methodology he develops in consultation with the Pacific Northwest Planning Council, BPA customers and various regulatory agencies in the Northwest. The consultation process has involved a combination of written proposals and comments, legislative-style hearings, informal meetings and face-to-face negotiations--all transcribed or summarized for the record. Several parties, primarily BPA's investor-owned utility customers, have commented that this consultation proceeding was not in accordance with BPA's administrative rule governing-the residential exchange, section VI of the 1981 methodology (18 C.E.R. §35.13a(d)(6)). These comments were predicated on an allegation that the ongoing proceeding was somehow fatally different from the proceeding that led up to the Administrator's decision on the 1981 ASC methodology. (*E.g.*, letter of A. Alexanderson, R. 119.) These claims are incorrect. The consultation process is consistent with governing statutes and regulations.

Section 5(c)(7) of the Northwest Power Act, 16 U.S.C. §839c(c)(7), does not define "consultation" or in any way limit the term to any particular form of proceeding. It is reasonably clear from the statute that formal evidentiary hearings are not required. Neither are negotiations an essential part of the process. When Congress intended either of these two procedures necessarily to apply it said so in sections 7(i) and 7(1) of the Northwest Power Act. 16 U.S.C. §839e(i) and 16 U.S.C. §839e(1). The statute leaves it to the discretion of the Administrator to choose the public process best suited to administering the residential exchange program.

Section VI of the 1981 ASC methodology, which governs changes to that methodology, does not constrain the Administrator to a particular form of proceeding. That rule merely states "[t]he Administrator, at his or her discretion, * * * shall initiate a consultation process as provided in section 5(c) of the [Northwest Power) Act." The methodology simply anticipates that, prior to a revision or reformation of the methodology, a public proceeding will occur in which the views of the public (particularly those of the three statutorily designated groups) will be considered by the Administrator. FERC has held that section VI of the 1981 methodology is a BPA administrative rule not subject to FERC review. *See* 48 Fed. Reg. 46,972 (1983).

There is nothing inherent in the word "consultation" that would force a different conclusion. The essence of consultation is provision of an opportunity to receive information and advice from another. "Consultation" is a council or conference, as between two persons, usually to consider a special matter. It is the act of consulting. "Consult" means to ask advice of, to seek the opinion of, or to apply to someone or something for information. *Webster's Third New International Dictionary of the English Language Unabridged*, G.&C. Merriam Company, Springfield, Mass. (1976).

Precedents involving statutes requiring consultation prior to decision establish that "consultation" can occur in various ways. *Mid-America Regional Council v. Mathews*, 416 F.Supp. 896, 903-904 (W.D.Mo. 1976), involved a statute requiring the Secretary of Health, Education and Welfare to consult with governors of affected states prior to designating an entity as a "health systems agency." In *Mid-America* the secretary had given affected governors the opportunity to review the applications for designation and to submit their written recommendations and comments to HEW. Plaintiffs argued that the secretary's procedures were insufficient. Rejecting plaintiffs' position, the court concluded that the provision regarding consultation was intended only to ensure that HEW received the written recommendations, criticisms and views of the governors and did not mean that HEW had to provide conferences or negotiate the designation with the governors:

> [the] Congressional requirement was only intended to insure that the agency received the recommendations and views of the Governors and did not mean that the agency, which was heavily burdened to implement the Act within the appropriate time frame, was required to provide at any time, conference or negotiation meetings to the Governors and their staffs. [416 F.Supp. at 904.]

See also, *National Wildlife Federation v. Coleman*, 529 F.2d 359, 371-72 (5th Cir. 1976); and *Town of Milton v. Massachusetts Bay Transportation Authority*, 253 N.E.2d 844 (Mass. 1969). "Consultation" is not synonymous with "consensus."

The procedures adopted by BPA in this consultation proceeding were intended to facilitate the compilation of a full record on which to base this decision. The procedures were similar to those used in the determination of the 1981 ASC methodology. *See* Administrator's 1981 Record of Decision at 10. In each proceeding, BPA has used a combination of notice and comment rulemaking procedures and negotiations. Rulemaking procedures allow BPA to build a written record on which the average system cost methodology must be based. This is absolutely essential if the methodology is later challenged before FERC or the Court of Appeals. If the revised ASC methodology is based on the written record, BPA would be able to rebut any allegations that the methodology is somehow "arbitrary or capricious." BPA's investor-owned utility customers, for example, first threatened suit last November even before an ASC methodology proposal had been promulgated (R. 380). Since then, they have filed three lawsuits in Federal District Court and in the Ninth Circuit Court of Appeals.[8] Litigation seems inevitable over any methodology that might be determined in this proceeding.

There are similarities between the 1981 consultation and the present one, yet definite improvements have been made. The 1981 consultation proceeding was essentially an experiment with a novel residential exchange concept in a new statute. The Administrator was placed under a statutory deadline in which to determine the first ASC methodology, 1981 decision at 1-2,"and only a small record was compiled during the course of the proceeding.

To build a comprehensive record in the current consultation, BPA first asked the public to respond to 17 questions regarding problems with the existing methodology. Then, based on those responses, BPA published a written proposal on February 3, 1984. (R. 8.). Interested members of the public commented on the proposal and then submitted reply comments responding to each other. (R. 443-850). Written comments were solicited again on May 15 and 17, 1984. (R. 2945, 2982). In all, four opportunities for written comments have been provided in the current consultation, as opposed to a single opportunity in 1981.

Negotiations have played an equal part in the process of building a record. Negotiations often occur during rulemaking proceedings, but do not make the resulting rule a contract. BPA has met to discuss possible methodologies with private utility chief executives, public power representatives and industrial customer groups. Minutes of these meetings are included in the record. BPA staff traveled throughout the region to explain their proposed methodology in four transcribed public sessions. (R. 915-1150). On April 20, 1984, BPA held a public comment forum where a wide range of views was expressed. (R. 1317). Unfortunately, BPA's investor-owned utilities staged a walk-out at this proceeding, choosing not to listen to comments pro and con.

Beginning on April 20, 1984; and extending over the ensuing three weeks, BPA staff and customer and public representatives negotiated face-to-face on a possible compromise methodology. Investor-owned utilities sent a representative to the negotiations; however, he was instructed not to participate. (R. 1393-2810). All negotiation sessions were transcribed and have been incorporated into the record. *Id.* BPA staff distributed a negotiated methodology for public comment on May 15, 1984. (R. 2945).

Essentially, criticism about the adequacy of the current consultation proceeding has come from parties who have alleged that the proceeding lacked essential ingredients of face-to-face discussions and negotiations. Yet, these same parties have elected to boycott the discussions and negotiation sessions that have formed an intregal part of the process. Instead of a valid criticism, this is more an attempt by one group of BPA customers to filibuster a proceeding convened at the request of BPA's public agency and DSI customers. However, the consultation process cannot be made subject to the veto of any customer group.

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[8] *Public Utility Commissioner of Oregon v. BPA* (D. Or., Civil No. 84-270-PA), dismissed March 21, 1984, appeal pending, 9th Cir. No. 84-3722; *Public Utility Commissioner of Oregon v. BPA* (9th Cir. No. 84-7185); *Pacific Power & Light Company v. BPA* (D. Or., Civil No. 84-261-PA).

C. The Timing Of The Current Consultation Proceeding

BPA began the ASC methodology proceeding two years after FERC first approved the 1981 methodology. This is consistent with the BPA administrative rule governing changes in the 1981 methodology. *See* section VI.

The intent of this rule was to keep the 1981 methodology in place for one year in which to gain experience. Several commenters have suggested that the rule should be construed to preclude methodological changes until one year after final FERC approval of the 1981 methodology. However, it was never BPA's intent to retain the 1981 methodology longer than the one year of experience, whether or not abuses arose--as they have. This construction of the rule is reflected in BPA's October 7, 1983, *Federal Register* notice, 48 Fed. Reg. at 45830, which states:

> …the new consultation process has been initiated no sooner than 1 year after the previous methodology was adopted by BPA on August 26, 1981, and approved by the FERC on October 14, 1981. *See* 46 Fed.Reg. 50,517 (1981), corrected at 46 Fed.Reg. 55,952 (1981). Although the FERC approval was granted on an interim basis, this action satisfies the requirements of 18 C.E.R. 35.13a(d)(6). [R. 4-A6].

After nearly two years of experience, BPA realized there were serious problems with the existing methodology. The methodology was too contentious and open for abuse. Although a number of appeals have recently been settled, every one of 60 submittals was contested before FERC and four lawsuits were filed with the U.S. Court of Appeals for the Ninth Circuit.

The existing methodology had also been abused. Last year, BPA had to revise submittals by Portland General Electric Company because they contained the costs of terminated nuclear plants. Inclusion of these costs is prohibited by the Northwest Power Act. As noted earlier, BPA's customers insisted that the consultation proceeding be instituted in 1983. The Public Power Council noted in May of 1983 that it had been more than one year since FERC had approved the 1981 methodology and that a new consultation proceeding should be commenced under section VI. (R. 84-85).

For all of these reasons, BPA decided to initiate an open, public process to review the 1981 methodology and attempt to develop a new methodology which would result in less contentious submittals and eliminate the abuses. The consultation proceeding was initiated on October 7, 1983 (48 Fed. Reg. 45,829)--nearly two years after FERC first approved the 1981 methodology. (R. 2).

D. Allegations Of Bias Or Predisposition

On March 9, 1984, the Public Utility Commissioner of Oregon, Pacific Power & Light Company, Portland General Electric Company, and CP National Corporation filed a complaint for declaratory and injunctive relief in the United States District Court for the District of Oregon, Civil No. 84-270-PA. The parties alleged that the Administrator was "absolutely committed" to changing the ASC methodology rule to the parties' economic detriment. (R. 6711). The parties based their allegations solely upon two affidavits one by a Pacific Power Light Company executive, Mr. David Bolender, and the other by a Portland General Electric Company executive, Mr. Robert Short. (R. 6721, 6725). Both affidavits claim to recount excerpts of conversations that took place in private meetings with the Administrator.

The action in District Court was dismissed for lack of jurisdiction on March 21, 1984. The parties then appealed the District Court decision and filed an original "complaint" in the United States Court of Appeals for the Ninth Circuit, No. 84-7185. These parties did not raise an allegation of bias on the part of the Administrator during the entire administrative consultation proceeding. On the last day of the final comment period, Portland General Electric Company submitted into the record a letter stating that "Mr. Johnson should disqualify himself and management reporting to him from making any decision to change the ASC methodology" (R. 6708).

On March 29, 1984, the Administrator addressed the controversy over allegations that he was somehow biased. (R. 1116). In letters to each of the two affiants mentioned above, the Administrator offered to submit to a transcribed question-and-answer session on questions of bias, which was to be included in the record of the ASC methodology proceeding:

> I strongly disagree with your characterizations of my statements in the affidavits and with your use of my statements out of context. I propose the following procedures to assure that the record in BPA's consultation proceeding may be made clear regarding any alleged predisposition on my part.
>
> I am willing to respond to questions posed by a single representative of your mutual choice in a transcribed session lasting approximately one hour. All questions must relate to your allegations of my improper bias in the consultation proceeding… BPA will provide the court reporter for this question-and-answer session which will occur in my office. The transcript will be included in the record of the consultation proceeding…
>
> In return, I request each of you [the two affiants] to submit to a question-and-answer session with the same ground rules. Topics of inquiry would concern your allegations regarding my improper bias on issues concerning the average system cost methodology and our conversations relating to this matter. … Transcripts of these sessions would also be included in the record of the consultation proceeding.

In response, the affiants refused the Administrator's offer to supplement the administrative record with the answers of the Administrator and the two affiants to questions regarding allegations of bias. (R. 117). Also, the affiants declined to respond to a follow-up inquiry from BPA's General Counsel, which asked them to suggest alternative "ground rules" if they found the Administrator's question-and-answer procedures unacceptable for any reason. (R. 118).

The record clearly reflects the Administrator’s intention to determine an ASC methodology based on the record compiled in this proceeding. In public comments of April 20, 1984, he stated:

> My mind is not made up, therefore, the Administrator’s mind is not made up. We have laid out a proposal. That proposal has started a debate. It is a heated debate; I respect that. This is very important to everyone assembled in this room, and I will be reading all the comments that are made, and there will be oral arguments about a week from now, and I will be here to listen to that, and I will certainly take account of everything that is said here today, and I can only make a decision in the final cut on the record. In other words, on the good, reasoned logic and the persuasion of those people, not only assembled here today, but others who have elected to speak to this important subject. [R. 1324.]

This decision follows the prescription of that public statement.

CHAPTER THREE

BPA'S PROPOSAL OF FEBRUARY 3, 1984

Because the so-called jurisdictional costing approach was not yielding satisfactory results under the 1981 ASC methodology, BPA proposed to replace it with a uniform cost approach in a new ASC methodology. Aspects of the 1981 methodology not addressed in the proposal were to remain unchanged.

BPA proposed a new source of ASC data that was intended to reduce controversy and facilitate ease of administration. As the new source of data for computation of residential exchange subsidies BPA proposed the FERC Form No. 1, a compilation of financial and operating information prepared annually in accordance with FERC's Uniform System of Accounts for Public Utilities and Licensees (18 C.F.R. Part 101).

For each exchange period under the proposed methodology, *i.e.*, each calendar year, the participating utility would only include in its ASC actual costs documented in that Form 1. There were to be limited exceptions. First, equity return and taxes for participating investor-owned utilities would be determined in accordance with procedures described later in this notice. Second, fuel purchases from utility affilates pose special regulatory problems which were also to be treated separately. Third, participating utilities not required to submit Form 1 were to submit audited, actual data in a calendar-year format comparable to FERC Form 1.

Each participating utility would receive one determination of its ASC "in each year." *See* section 5(c)(1) of the Northwest Power Act. This was to replace the multiple determinations in each year now made by BPA for each jurisdiction in which a participating utility provides retail residential service.

The February 3, 1984, proposal had characteristics similar to ratemaking based on an historical, calendar test year incorporating end-of-year data. Each participating utility was to be permitted to include the same types of costs in ASC, based on actual data from the same calendar-year period. It was to have been uniform in comparison to the current methodology, which relies on data from retail rate proceedings throughout the Northwest, each using different ratemaking methodologies and test years.

However, the proposal noted that BPA would not accept at face value the numbers included in FERC Form 1 accounts by participating utilities. Filings would continue to be scrutinized by BPA and all improper costs were to be disallowed. Each ASC filing would contain a statement, signed by the participating utility's auditor, stating that all data submitted by the utility were compiled in strict compliance with FERC's Uniform System of Accounts and with procedures for reporting the costs of conservation and affiliate fuel transactions. Any filing which does not contain this auditor's statement would not be accepted by BPA for determination of ASC.

Other significant features of this proposal were:

1. Inclusion of transmission costs in ASC, but only up to the level of transmission costs included in the BPA priority firm rate.

2. Exclusion of Construction Work In Progress from the calculation of ASC.

3. Inclusion only of generating costs incurred in the production of electric power and energy to meet retail loads.

4. Inclusion in ASC of conservation costs.

5. Use of a national average for return on equity for use in determining the equity return allowance for participating investor-owned utilities.

6. Inclusion in ASC of fuel costs with safeguards to protect against unreasonable profits to utility affiliates.

7. Inclusion of investor-owned utility income taxes only at the participating utility's effective tax rate.

CHAPTER FOUR

RESOLUTION OF SUBSTANTIVE ISSUES

I. THE SOURCE OF DATA FOR THE AVERAGE SYSTEM COST METHODOLOGY

A. Summary Of Positions

The 1981 methodology is based on the "Jurisdictional Cost Approach," an approach based on findings of retail ratesetting bodies modified by specific instructions required by the Northwest Power Act. BPA has had several problems with the jurisdictional approach. The primary drawback to the jurisdictional approach is that state regulators are not responsible for enforcing the requirements of section 5(c). *See supra* at 12-14.

BPA proposed to replace the jurisdictional cost approach with a uniform costing approach in the proposal of February 3, 1984. The proposal relied on FERC Form 1, a compilation of financial and operating information prepared annually in accordance with FERC's Uniform System of Accounts for Public Utilities and Licenses. (18 C.F.R. Part 101). The uniform costing approach has characteristics similar to ratemaking based on an historical, calendar test year incorporating end-of-year data. Each participating utility would be permitted to include the same types of costs in ASC, based on actual data from the same calendar-year period. This approach would have eliminated the frequent debate concerning projections of costs, loads, and sales for resale credits. Filings would still require scrutiny to eliminate improper costs and to ensure proper functionalization.

The uniform cost approach and BPA reliance on FERC Form 1 was criticized by almost everyone because it relied on historical data and did not match cost data in BPA's PF rate. Puget, Derick, R. 2348-2349; PNGC, Johnson, R. 1515; PGE, R. 705; Puget, R. 623; Utah, R. 615; IPC, R. 634; MPC, R. 645; WWP, R. 499; Hemmingway, R. 602; OPUC, R. 166A.

BPA's staff proposal of May 15, 1984, retains the so-called jurisdictional approach. The negotiating parties and comments received by investor-owned utilities unanimously supported the jurisdictional approach. The staff proposal clarified two important elements of BPA's statutory role: (a) independent determination of costs, regardless of the findings of retail rate regulators; and (b) greater involvement by BPA in retail rate cases of utilities participating in the residential exchange program.

B. Decision

Jurisdictional cost data ensures that an exchanging utility will be able to include its current costs in ASC and also provides -a matching of the costs between the BPA priority firm rate and the ASC. If handled correctly, its use avoids the necessity of elaborate and administratively burdensome "true-ups" or attrition allowances which might be required if historical cost data, such as those contained in FERC Form 1, were used.

Jurisdictional costs have been subjected to an initial review during the regulatory process, even though this regulatory review is not designed to determine whether the costs are appropriate for inclusion in ASC. In contrast, the cost data included in the FERC Form 1 are subject to virtually no regulatory scrutiny.

The jurisdictional approach also provides regional customers the opportunity to participate in the initial review of the costs used in the ASC. The DSIs routinely participate in state ratemaking proceedings. This opportunity would be lost if FERC Form 1 data were used.

BPA must assume the responsibility of reviewing all costs and loads for appropriateness according to section 5(c). The Administrator is responsible for ASC determination and this responsibility cannot be delegated to state regulatory officials. If the costs are based on substantive commission findings, there is a rebuttable presumption under the 1981 methodology that these costs are appropriate contract system costs. If, however, costs are challenged by a party or by BPA, the Administrator may disallow those costs based on an independent review. The exchanging utility is ultimately responsible to substantiate the accuracy and reasonableness of its ASC filing.

II. DETERMINATION OF WHETHER TRANSMISSION COSTS SHOULD BE CONSIDERED RESOURCE COSTS WITHIN THE MEANING OF SECTION 5(c)

A. Summary of Positions

Transmission investments and expenses were included in the 1981 ASC methodology as the outcome of a negotiated settlement. The Administrator’s 1981 decision is silent on the justification for inclusion of such transmission costs, except to note certain practical considerations unique to the first ASC consultation proceeding. Neither does FERC Order No. 337 address the merits of including transmission costs in ASC.

In the proposal of February 3, 1984 (R. 15-17), it was concluded that Congress did not require BPA to subsidize participating utilities for their transmission costs. For reasons of equity alone, BPA proposed the inclusion in the ASC methodology of a transmission “adder,” which could not exceed the level of transmission costs included in the BPA priority firm rate. BPA transmission costs would be an upper limit, or cap, on the proposed transmission adder. Participating utilities that elected to use the adder would be required to include in their ASC filing FERC Form 1 account data on costs functionalized to transmission. No radial line costs were to be included in the adder. All wheeling revenues would have been credited against FERC Form 1 transmission costs.

Comments on transmission costs for the ASC proposal ranged from excluding all transmission costs (ICUA, R. 6552; DSI, R. 6593) to including all transmission costs as under the 1981 methodology. (PGE, R. 707; Puget, R. 625).

Comments suggesting exclusion of all transmission costs were based on the argument that transmission facilities are not “resources” as used in section 5(c)(1) of the Northwest Power Act.

Inclusion of those costs is beyond the authority of the Act. Commenters also suggested that inclusion of transmission costs creates an incentive for utilities to construct unnecessary transmission facilities. (DSI, R. 19A).

Several investor-owned utilities argued that all transmission costs should be included on the basis that both transmission and generation costs are resource costs, that BPA's half of the exchange includes both transmission and generation, and that a utility's ASC must include both transmission and generation costs in deference to "wholesale rate parity" (R. 626).

The investor-owned utility commenters argued that exclusion would distort the comparison of "coal-by-wire" (which could be excluded) and coal-by-train (which would be included as a generation cost). They also claimed that including transmission costs would not distort rational economic choices by providing financial incentives to construct unnecessary transmission lines. There would be no such incentive, state the commenters, because all transmission costs are not recovered through the residential exchange and because traditional ratemaking procedures would still provide a check on the prudence of transmission expenditures (*e.g.*, Puget, R. 625-627).

Between these two extremes there have been proposals to include only a portion of transmission costs. The DSIs suggested an option which would allow existing transmission costs for lines which connected a resource with the load center. This would require definition of existing lines which would meet that criterion. That criterion would also apply to new transmission lines as well. (R. 2633-2634; 6597-6598). The DSIs argue that only those lines that integrate resources should be included. They offered four proposals for defining allowable transmission (R. 6598-6599).

Various other transmission "cap" proposals were offered, ranging from 1.8 mills which would exclude costs associated with fringe area transmission facilities, dedicated feeders, and low voltage transmission not related to any generating resource (WWPUD, R. 561-563), to a 1.5 mill cap area as discussed by the DSIs. (R. 175).

Following receipt of written comments and at the conclusion of negotiations, BPA staff offered a revised transmission cost proposal on May 15, 1984, to allow in the residential exchange subsidy all transmission plant in service as of July 1, 1984, as defined by the FERC uniform system of accounts. For transmission plant placed in service after July 1, 1984, staff proposed to allow transmission plant limited to the lesser of the costs of transmission facilities required to transmit power from the utility's generating resources to the utility's load area or the costs of facilities necessary to interconnect with the closest feasible point on BPA's transmission system, plus wheeling costs to the utility's load area. A participating utility would remain free to construct facilities that were more costly than those facilities necessary to interconnect to the'BPA system; however, the additional amount would not be subsidized by BPA through the residential exchange program (R. 2947).

B. Discussion of Positions

Commenters have suggested variations from excluding all transmission costs to including all transmission costs as determined by exchanging utilities or rate regulators, with several alternatives that cover the spectrum between the two extremes. Proposals which define a cap could distort the comparison between "coal-by-wire" or coal by some other transmission mode. By limiting the transmission component at a specific level, the cost of transmitting power over a line from a mine-mouth plant to a load center might be excluded in contrast to a load center coal plant which would include the cost of transporting the coal to the plant. A cap provision of this kind may exclude a resource cost (Puget, R. 627; R. 2515).

Including only existing transmission that integrates resources to load centers presents a definitional problem. The transcript of the consultation process is replete with discussion of the proper definition of generation integration (R. 2507-2518; R. 2592-2610, R. 2630-2649, R.2796-2803). Definitions of generation integration can range from only lines that connect the first step-up transmission point to lines which connect to load areas at relatively low voltages. It appears to be more difficult to define generation integration in relation to existing lines where the original purpose for a line is different from its current use and where that use may change again in the future. It is also difficult to define a load center or area when many service areas are spread over a large territory. Nearly every party had a different proposal for defining the appropriate transmission lines to include in the calculation of ASC, aside from total exclusion or inclusion.

Including all future transmission facilities, as defined by the FERC Uniform System of Accounts, would likely provide an incentive for utilities to construct unnecessary transmission facilities, a portion of the cost of which could then be subsidized through the residential exchange. These new facilities might be built exclusively to serve out-of-region markets, clearly not a resource cost associated with the residential exchange. The ASC methodology should include the principle that only future transmission that integrates resources to regional load should be included. This is much easier to determine before a transmission line is completed than after it is completed and in use.

C. Decision

From a legal standpoint, BPA believes that there is no requirement that transmission costs be included in resource costs for calculation of the residential exchange subsidy. BPA is directed by section 5(c)(7) to develop a methodology for calculating "the average system cost of that [participating] utility's resources…" *See* section 5(c)(1). Resource is synonymous[**] with generating facilities and conservation measures, not with transmission facilities.

Resource is narrowly defined by section 3(19) of the Northwest Power Act as:

> (A) electric power, including the actual or planned electric power capability of generating facilities, or
>
> (B) actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure.

Elsewhere in the statute, the terms "resource" and "resources" are used synonymously** with generating facility and conservation measures.[9] Where Congress intended to define the cost of resources to include more than generation, it did so expressly. Section 3(4)(8) of the Northwest Power Act defines "cost-effective" resource by reference to a number of ancillary costs including" … if applicable, the cost of distribution and transmission to the consumer…"

BPA concludes that there is no requirement in the Northwest Power Act that BPA subsidize transmission investments and expenses under the residential exchange program. However, it does not follow that the 1981 methodology included improper costs. The Act does not contain a specific prohibition of including transmission costs in ASC, although BPA would tend narrowly to construe statutes that add to its revenue requirement. There is nothing in the statute that would lock the Administrator into a single methodology. When revising the ASC methodology the Administrator is provided considerable discretion by section 5(c)(7). The inclusion of transmission costs is permitted by the Act but not required. The question for the BPA Administrator to decide then becomes one of policy.

Although the case is by no means compelling, BPA is persuaded to include in ASC transmission costs which reflect integration of generating resources.

The exchange of views in the consultation proceeding on the issue of what amount of transmission is necessary to integrate a resource with a load area produced no consensus. For existing transmission facilities, voltages can range from a cut-off point between distribution below 69 kV to as high as 230 kV. A consensus on voltage level was not reached. The original use of existing transmission facilities often differs from its current use; what was once distribution may be transmission and vice versa. Moreover, defining a point where a transmission line enters into a load area and then becomes either load area transmission or distribution can be difficult. As a result of the lack of consensus and the difficulty in defining existing transmission which is used for integrating resources, BPA has chosen to include in the calculation of the ASC subsidy all existing transmission, as defined by the FBRC Uniform System of Accounts, in service as of July 1, 1984, the effective date of the revised ASC methodology adopted in this decision.

New transmission facilities pose a less difficult problem in defining those lines which are constructed to integrate a resource with a load area. These lines can be reviewed in the context of justification for construction. Duplicate or redundant facilities will not be subsidized. BPA has chosen to limit the inclusion of future transmission facilities, based on the following criteria:

> For transmission plant commencing service after July 1, 1984, transmission plant costs which can be exchanged are limited to transmission facilities that are directly required to integrate** resources to the-transmission system grid. Specifically, transmission costs which can be exchanged are limited to the lesser of the costs of transmission facilities required to transmit power from the

[9] *E.g.*, the definitions of "Federal base system resources" in §3(10), "major resource" in §3(12) and "renewable resource" in §3(16), 16 U.S.C. §§839x(10), (12) and (16), respectively; and §6 (conservation and resource acquisition), 16 U.S.C. §839d. Resources characteristically "serve [a BPA customer's] firm load," 16 U.S.C. §839c(b)(1)(A) and (B), or "meet, on a planning basis, the load requirement . . .," 16 U.S.C. §B39c(c)(4)(C)(i).

> generating resource to the exchanging utility's system or the sum of the costs of the transmission facilities required to integrate the generating resource to the BPA system and the wheeling costs necessary to wheel the power over the BPA system to the exchanging utility's system. If the utility chooses to construct facilities that are more costly than the facilities required to interconnect to the BPA system, the total costs of that facility to be exchanged shall be no greater than the facility costs that would have been incurred to interconnect with the BPA system.

BPA has no intention of interfering with utilities' decisions on what transmission to construct as is suggested by some commenters. However, BPA does not believe it is appropriate to require other ratepayers in the Northwest to subsidize transmission decisions which are clearly beyond the bounds of integrating a resource. If a utility chooses to build new lines for other purposes such as bulk power sales, they may make an economic decision which is to their benefit. However, those costs would be excluded from ASC calculations. In the case of lines built for bulk power sales, the corresponding wheeling revenues from those sales using the new bulk power lines would be excluded in calculating a revenue credit against ASC if the participating utility can make the appropriate demonstration. (PP&L, R. 6688).

III. SUBSIDIZATION OF CONSTRUCTION WORK IN PROGRESS

A. Summary Of Proposals

One of the costs a utility incurs while constructing new plant is that of financing capital investment, which may be referred to as carrying charges. There are two alternative methods for treating carrying charges incurred during the construction period. One method capitalizes the carrying charges as an Allowance for Funds Used During Construction (AFUDC). Under this method the carrying charges are computed periodically (usually monthly) and are added to the direct cost of the construction (FERC Account 107). The total cost of the completed construction will include not just direct costs of land, labor, and materials; it will also include the carrying charges recorded during construction. These charges will be fully recovered from the ratepayers during the life of the plant as depreciation expense. AFUDC is recorded as income by the utility as the carrying charges are accrued during the construction period. Actual cash payments from ratepayers to cover the carrying charges begin when the plant is completed.

The second method for recovering construction carrying charges is through inclusion of Construction Work in Progress (CWIP) in rate base. Under this method CWIP is treated like plant in service. The utility recovers carrying charges currently from ratepayers, rather than adding the charges to the cost of construction. The carrying charges are determined by the allowable return (debt and equity) that is applied to utility investment which is used and useful. The return on CWIP is recorded as income on a current basis (just as AFUDC) and actual cash payments are made by the ratepayers currently (unlike AFUDC).

In BPA's proposal of February 3, 1984, CWIP was excluded from the calculation of ASC due to the difficulty of retroactively adjusting ASC if CWIP were to have been subsidized for a construction project that was later terminated (R. 17). The residential exchange subsidy cannot include the costs of any facility which is terminated prior to initial commercial operation. 16 U.S.C. §839(c)(7)(c). BPA's February 3 proposal was not intended to prejudge the choice between the CWIP and AFUDC methods by any state regulatory body.

Pacific Power & Light Co. suggests that CWIP should be allowed in rate base because retroactive adjustment has not been a problem under the 1981 methodology. However, PP&L recommends that if CWIP is excluded, the effective tax rate should be adjusted to exclude related interest expense. (R. 492-493). Since income taxes are to be excluded from ASC, this tax adjustment will not be necessary.

In contrast, the DSIs state that CWIP should be excluded from calculation of ASC (R. 62A-72A). They suggest that the difficulty of recovering exchange subsidy payments when construction projects are terminated has been demonstrated by experience under the current methodology. The DSIs suggest the problem also arises if the construction project is completed but then is used to serve extraregional loads or new large single loads within the Northwest. *See* section 5(c)(7)(A) and (B) of the Northwest Power Act. The DSIs also claim that inclusion of CWIP in calculation of ASC forces BPA and its customers to lend exchanging utilities their construction financing costs. The DSIs also note that no Northwest regulatory jurisdiction permits inclusion of 'CWIP in rate base as a general practice.

Washington Water Power Co. (R. 625), Montana Power Co. (R. 649), and Portland General Electric Co. (R. 709) suggest that exclusion of CWIP is inconsistent with the concept of wholesale rate parity. PGE and the Oregon utility commissioner (R. 708, 174A) note that FERC allows CWIP for purposes of wholesale ratemaking and that BPA includes CWIP (for Washington Public Power Supply System plants) in its priority firm rate.

Commenter Leroy Hemingway suggests that elimination of CWIP from ASC removes a regulatory tool that may provide needed flexibility in recovering resource costs (R. 605).

Western Washington PUDs suggest that BPA should exclude CWIP for generation plant but not for transmission plant (R. 564-565).

B. Discussion Of Positions

All major jurisdictions in which participating utilities are regulated (Oregon, Washington, Idaho, and Montana) currently do not allow CWIP in rate base for purposes of determining retail rates. Thus, under the jurisdictional costing approach, which BPA has decided to retain, CWIP has become an academic issue for investor-owned utilities that participate in the residential exchange.

Publicly owned utilities that set their rates on a cash basis do not use rate base to determine part of their revenue requirements. They only use rate base to spread the revenue requirement among their different customer classes. (*See* Johnson, PNGC, R. 2285.)

All participants in the negotiation sessions agreed that generating CWIP would be excluded from rate base. *See* Ailshie, BPA, R. 2235; Tanner (DSI), R. 1707.)

C. Decision

Since CWIP is not allowed by regional regulatory authorities, it would not be appropriate under the jurisdictional approach to include CWIP in the calculation of ASC, thereby requiring BPA's customers to subsidize participating utility construction projects.

Moreover, BPA must comply with the proscription of section 5(c)(7)(C), 16 U.S.C. §839(c)(7)(C), which states that ASC shall not include "any costs of any generating facility which is terminated prior to initial commercial operation." This provision requires BPA to recover amounts included in ASC for CWIP on construction projects which are subsequently terminated. *See* Administrator's 1981 decision at 8. However, it is quite difficult to reverse the effects of allowing a CWIP return in ASC. From this perspective, the better policy is to include generating resources in the calculation of ASC only when they go into commercial operation. No CWIP will be included in the rate base calculation of ASC under the methodology adopted in this Record of Decision.

With regard to transmission CWIP, BPA has separately decided in this decision only to include in ASC transmission that is necessary not redundant. Such a determination will not be made until the line is completed. It would be inappropriate to include a transmission facility in ASC before it went into commercial operation for the same reasons that generation CWIP is excluded. This result is both equitable and easy to administer.

IV. TREATMENT OF EQUITY RETURN

A. Summary Of Positions

The jurisdictional costing approach has caused serious concern that equity returns allowed by regulatory agencies have indirectly compensated participating utilities for the costs of generating facilities terminated prior to initial commercial operation. Although not necessarily inconsistent with relevant state laws, such allowances violate section S(c)(7)(C) of the Northwest Power Act if included in ASC. In its proposal of February 3, 1984, BPA therefore proposed a generic method for determining the equity return component of ASC for investor-owned utilities.[10] Compare, Generic Determination of Rate Return on Common Equity for Electric Utilities, FERC Docket No. RM80-36-000, 47 F.R. 38,332 (1982).

In the first quarter of each year, BPA proposed to determine and publish a national-average equity return allowed by retail rate regulators for electric utilities during the preceding calendar year. Equity return data would be derived from published statistical sources on publicly traded electric utility securities. This national-average number would be used as the equity return allowance for each participating investor-owned utility throughout the relevant exchange period.

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[10] Under the February 3 proposal, no change would have been made in the way that capital costs were determined for publicly-owned and cooperative utilities.

BPA thought that this national-average number might be excessive for two reasons. First, it is reasonable to expect that regulators throughout the nation increase equity returns to compensate for terminated plant costs--either implicitly or explicitly. *See*, *e.g.*, *Consumers Council v. Public Utilities Commission*, 447 N.E.2d 749 (1983). As noted earlier, such costs cannot be included in ASC. Second, provisions of the Northwest Power Act should reduce the equity return requirements of Pacific Northwest utilities vis-a-vis the national average. The residential exchange, the opportunity to purchase firm power for load growth under section 5(b)(l), the conservation funding available from BPA under section 6, and other provisions of the Northwest Power Act reduce the financial risks for regional utilities in relation to utilities not affected by the Northwest Power Act. BPA proposed to compensate for these two circumstances by reducing the national-average equity return one percentage point (100 basis points) for use in the ASC methodology.

In a BPA staff proposal of May 15, 1984, it was proposed that the return component of the residential exchange subsidy be calculated in the following manner:

(a) for private utilities, multiply rate base by the embedded cost of long-term debt;

(b) for publicly owned utilities, use the lesser of the average embedded cost of debt or 75 percent of the 90 day Treasury bill rate for the proceeding calendar year times rate base (*see* May 15 proposal, R. 2966); and

(c) for cooperatives, use the greater of the average embedded cost of debt times rate base or the rate of return necessary to meet "TIER" (times interest earned ratio) requirements.

Investor-owned utility commenters generally asserted that common equity is a resource cost. (Puget, R. 6576; CPN, R. 6554-6555; IPC, R. 6662; PGE, R. 6709; WWP, R. 6665; UP&L, R. 6576-6577). Removal of equity costs would not be consistent with the concept of wholesale rate parity. (Puget, R. 2347-2348; PP&L, R. 6678-6679; IPC, R. 6662).

IOU commenters state that the BPA staff's proposal of using the weighted cost of long-term debt as the-rate of return component of the residential exchange subsidy would be insufficient to allow recovery of actual generation and transmission costs through ASC. A capital structure composed entirely of debt securities would carry a higher cost than a capital structure with a mix of equity and debt. Debt securities are less risky since the return on equity serves as a cushion by absorbing fluctuations in earnings. (PP&L, R. 6679). Commenting public utility commissions sham this viewpoint. (IPUC, R. 2144; OPUC, R. 6581-6583; WUTC, R. 6561).

In addition, the IOUs point out that the cost of debt includes coverage without which they would not be able to issue debt. (PP&L, R. 6679). BPA's staff proposal does recognize that coverage, at least for the cooperatives, is a resource cost. *See* Footnote d. The staff's proposal allows only one times debt coverage for the IOUs which is below most utility's debt interest coverage. (PP&L, R. 6678-6682).

IOU commenters also criticize BPA's concern that allowed equity could provide compensation for generating resources terminated prior to completion and the risks of such termination. Pacific Power & Light claims, without documentation, that most regulatory jurisdictions allow full amortization of terminated plant costs apart from equity return. (PP&L, R. 6680-6681). If no terminated plant costs are included dn equity return, then adjustments are unnecessary and unwarranted. *Id.* The Washington Utilities and Transmission Commission points out that terminated plant costs in ROE can be identified and removed, at least in some jurisdictions. An alternative measure for the costs of resources associated with equity capital should not be necessary. (WUTC, R. 6561).

The various publicly owned utility commenters had mixed opinions about a rate of return subsidy component. Snohomish County PUD supported the current ASC methodology on rate of return as applied to public utilities similar to Snohomish. (Hutchison, WWPUC, R. 1834-1837). Springfield Utility Board urged that a national average equity return be applied. (Loveland, SUB, R. 2296). The Public Power Council supports using the embedded cost of debt. The PPC supports the embedded cost of debt as a proxy for the rate of return because returns allowed by the jurisdictional regulators contain terminated plant costs. (R. 6670-6671). Mr. Collins, an interested private citizen, recommended that no return component be allowed in ASC. (Collins, R. 1816-1817).

The Western Washington PUD Association believed that the return determined by rate regulators provides the most accurate measure of the cost associated with equity. They suggest, however, that BPA should adjust return allowed in ASC whenever it contains a terminated plant cost. (R. 759).

The PUDs of Clallam, Clark, Grays Harbor, Lewis and Mason County advocate use of the actual embedded cost of debt for the debt component and substituting the cost of "high grade" utility bonds for the equity component. (Saleba, R. 851). Current debt costs can be used in place of equity return because it is theoretically appealing, simple to administer, equitable, and consistent for all of BPA's customer groups. (*Id.*; Saleba, R. 2542-2543). In addition, using the weighted cost of debt would remove both an equity return component related to terminated plant costs and the risk of such termination. (WWPUD, May 24, 1984, p. 3).

The DSIs argued an entire spectrum of possibilities. As their primary position, they asserted that equity return is not a valid measure of the cost of resources and should be excluded. (R. 73A). The DSIs recognize that there are capital costs associated with resources. However, equity costs do not reflect capital costs, but only profits--the requirements of the investor, which are not a resource cost. (Tanner, DSI, R. 1772-74). However, the DSIs suggested as an alternative that BPA use the equity returns allowed by regulators, subject to a defined cap. (Taylor, DSI, R. 1819-1831, 2276).

As a DSI alternative to be used if BPA determined that the cost of resources includes an equity component, Dr. Taylor proposed using an exchanging utility's embedded cost of debt as a better measure of resource costs within the meaning of section 5(c). (Taylor, DSI, R. 1831). The DSIs assert that coverage requirements are not a major item for consideration in ratemaking for investor-owned utilities. In addition, the DSIs note that actual debt costs do not include any coverage ratio. (Taylor, DSI, R. 1825-26).

B. Discussion of Positions And Decision

Nearly all commenters agree that equity and coverage requirements reduce the risk of debt securities by providing a cushion that absorbs fluctuations in revenues. No one contends that this does not reflect prudent utility practice which benefits both ratepayers and bondholders. Lacking equity support, generation and transmission investments would most likely be financed at higher rates. (*See, e.g.* OPUC, R. 6581-82). BPA does not dispute this.

However, BPA cannot agree that equity returns allowed by regulators do not include, at least tacitly, terminated plant costs and the risks of such terminations. These may well be compensable for ratemaking purposes; however, section 5(c)(7)(C) of the Northwest Power Act prohibits their inclusion in ASC. The IOUs incorrectly assume that the cost of equity capital in excess of the cost of debt, *i.e.* the risks of the business enterprise, are resource costs within the limits of section 5(c)(7)(C). "If you use the embedded cost of debt, you are implicitly taking out [of ASC) that incremental amount related to equity financing--that risk of construction that really should not be in the cost…" (Taylor, DSI, R. 1818).

Unless the methodology adopted in this decision accounts for the terminated plant problem, BPA will be required to make difficult[**], controversial adjustments in each investor-owned utility ASC filing. *See* BPA's Average System Cost Report for Portland General Electric Co., Jurisdiction: Oregon (May 13, 1983); *See also* Average System Cost Report for Pacific Power & Light Co., Jurisdiction: Oregon (November 2, 1983).

ASC should include neither equity nor coverage requirements because these are costs related to default risk. BPA effectively eliminates default risk by guaranteeing the return on investment for residential and small farm loads.

Some may argue that this position is not reflective of ratemaking. However, the residential exchange program is not governed by ratemaking principles. In developing an ASC methodology the BPA Administrator has considerable discretion in deciding whether to permit inclusion of an equity return allowance and, if so, how that component is to be determined. It might well be that, given enough time, BPA could devise a finer-tuned measure of the cost of capital that was free of terminated plant costs. But it would still be controversial and subject to criticism by those who wanted the residential exchange subsidy to be higher, or lower.

References to "wholesale rate parity" do not force a contrary conclusion. This ambiguous phrase is not even found in the Northwest Power Act. If the methodology adopted in this decision provides rate relief to the residential customers of exchanging utilities, which it does in the amount of about $170 million per year, then the objectives of section 5(c) will be reasonably met. One of these objectives is the exclusion of terminated plant costs from the residential exchange subsidy. Another vital objective of, the Act is that BPA not become the "deep pocket" to which exchanging utilities can shift excessive or improper costs. *Supra* at 9. The Administrator's decision, which reasonably balances these conflicting objectives, should be conclusive. Under that decision, the residential ratepayers of exchanging utilities will continue to enjoy the lowest electric rates in the nation.

There seems to be little record support for treating cooperatives, publicly owned utilities, and investor-owned utilities differently on this question. Therefore, the appropriate measure of the overall rate of return for calculation of ASC will be the embedded cost of long-term debt for the exchanging utility. However, if depreciation expense is not included in retail ratemaking for the exchanging utility, then return will be equal to the lesser of: (1) interest expense plus depreciation expense, or (2) debt service plus revenue-financed capital expenditures. In no event will the sum of Contract System Cost and Distribution/Other costs be greater than the revenue requirement used to set rates.

V. TREATMENT OF INCOME TAXES IN THE RESIDENTIAL EXCHANGE

A. Summary Of Positions

BPA proposed to use the exchanging utility's effective income tax rate in determining ASC. Significant distinctions exist between tax regulations and the ratemaking policies adopted by regulators. Commonly, tax expenses included in rates exceed the amounts actually paid by the utility to the Internal Revenue Service and to state taxing authorities. Depreciation deductions, which may be claimed at an accelerated rate for tax purposes, are "normalized" over the service lives of assets. *See Public Systems v. FERC*, 709 F.2d 73 (D. C. Cir. 1983). Interest expense deductions are also normalized for ratemaking purposes. Investment tax credits, which reduce tax liability permanently, may also be amortized for ratemaking purposes. These ratemaking policies are designed by regulators to increase utility cash flow. However, there is no such policy expressed in section 5(c) of the Northwest Power Act. BPA's February 3, 1984, proposal was not intended to affect decisions of rate regulators to increase the cash flow of utilities for whatever policy reasons they adopt.

Western Washington PUDs commented that income and revenue-related taxes are not resource costs and should not be included in the residential exchange. Such taxes are incurred because of the nature of the taxpayer as an investor-owned corporation (WWPUD, R. 570). The residential exchange was not intended to eliminate differences in tax incurrence between public and private utilities, only to provide rate relief to the residential customers of the latter.

The DSIs agreed that income taxes are not costs of resources within the meaning of section 5(c) of the Northwest Power Act. They claim that there was no consensus on inclusion of income taxes in the 1981 methodology; instead, the issue was sublimated by emphasis on jurisdictional costing issues (R. 1505-06). Inclusion of income taxes, the DSIs state, gives investor-owned utilities more than "wholesale rate parity" with BPA's preference customers and destroys the competitive "yardstick" that preference was intended to create. (DSI, R. 4A).

The DSIs also note that the inclusion of state and local taxes in ASC provides an incentive for these taxing jurisdictions to use BPA as a "deep pocket" to fund local interests on a region-wide basis (R. 1428, 1429, 1438, 2252). Voters should not be able to vote for a tax and then shift the tax to BPA through the residential exchange (R. 1439).

The Public Power Council has recommended that taxes be excluded from ASC (R. 1499-1500).

Investor-owned utility commenters stated that income taxes are resource costs, generally because such taxes are included in a utility's cost of service for ratemaking purposes (*e.g.*, Puget, R. 2348).

The Idaho PUC commented that income taxes should be included in ASC. The PUC argued that taxes must be considered resource costs, because if a utility had no money to pay its taxes it would have no money to build resources (R. 2145). However, if income taxes were excluded, deferred income taxes should not be factored into the ASC methodology either. The Washington Utilities and Transportation Commission urged the inclusion of income taxes (R. 2286).

B. Analysis Of Positions And Decision

1. Statutory Analysis

The legislative history of section 5(c) of the Northwest Power Act makes it reasonably clear that, on the basis of the discretion granted him under section 5(c)(7), the Administrator may decide not to subsidize income taxes under the residential exchange program. The Senate Report accompanying S. 885, the Senate version of the bill that became the Northwest Power Act, states that section 5(c)(7) " … contains a list of costs to be excluded in the determination of 'average system costs'; <u>additional exclusions may be incorporated in the methodology</u> for determining average system cost under this section." S. Rep. 272, 96th Cong., 1st Sess. 27 (1979) (emphasis added).

The legislative development of the ASC provisions also supports' the approach that the Administrator has the discretion to exclude income taxes. As originally drafted, the residential exchange provisions fully defined the concept of average system cost. In S. 2080, introduced by Senator Jackson to the 95th Congress, and in H.R. 9020 introduced by Representative Meeds, "system cost" was defined as the:

> full cost to a private utility of acquiring, owning and operating the power facilities used or to be used to supply power purchased under §6(b) and shall be the sum of the following: (A) fixed costs, (B) operating expenses, including fuel, depreciation, taxes other than federal income taxes, federal and state income taxes, purchased and interchanged power costs, and wheeling costs, and (C) any other expenses related to the purchase of power, the construction, ownership, operation and maintenance of generating plants to the extent not included in (A) and (B) above. [S. 2080, 95th Cong., 1st Sess., §10(a)(2) (September 9, 1977); *See*, H.R. 9020, 95th Cong., 1st Sess. §10(a)(2) (September 9, 1977).]

S. 3418 and H.R. 13931, also introduced during the 95th Congress, dropped this "defined" approach, which never reappeared in any bill subsequently introduced. Instead, Congress simply directed the Administrator specifically to exclude those costs enumerated in section 5(c)(7)(A), (B) and (C). The Administrator has discretion to either exclude or include any other costs. S. 885 as amended by the House -- and the Northwest Power Act as enacted -- provided the Administrator with discretion to both determine ASC and develop the ASCM (in consultation with the Council). H.R. Rep. 976-II, 96th Cong., 2d Sess. 11 (1980); 16 U.S.C. §839c(c)(7).

Thus, nothing in the Act or its legislative history requires' the inclusion or exclusion of income taxes in computing the average system cost of a utility's resources. Resource costs are not defined in the Act. The exclusions required in section 5(c)(7) are not exclusive. Since the Act does not define resource costs, we have to look elsewhere to determine whether income taxes should be treated as a cost of a resource.

2. Legal And Policy Analysis

Although income taxes have long been held to be costs of service for ratemaking purposes, A.J.G. Priest, *Principles of Public Utility Regulation* 51-52 (1969); *cf. Galveston Elec. Co. v. City of Galveston*, 258 U.S. 388, 399 (1922); *Georgia Ry. Power Co. v. Railroad Comm'n.*, 262 U.S. 625, 633 (1923), they are not necessarily associated with the cost of specific resources, nor are they required to be included as a cost for purposes of the residential exchange, which is *sui generis*. Again, BPA stresses that section 5(c) does not require the determination of any sort of wholesale power rate.

The purpose of the residential exchange in the Act is, in the words of Senator Hatfield, to provide "power to private utilities for their residential loads at exactly the same rate as power sold to preference bodies." 126 Cong. Rec. S.14694 (daily ed. Nov. 19, 1960). This is accomplished when BPA "sells" power to exchanging utilities at the same rate applicable to preference customers. However, "sale" was not expected to achieve parity in the retail rates between preference customers and investor-owned utilities. H.R. Rep. No. 976, 96th Cong., 2d Sess. 60 (1980). Thus, the Act did not necessarily contemplate subsidizing all costs that result in rate disparity between public and private utilities. Rather, it assumes the differences inherent in the different forms of business organization will remain.

Earning a profit and the resultant income tax liability is one of the primary differences between the publicly owned and investor-owned utilities. This basic difference should not be affected by the residential exchange. Income taxes are a function of the nature of an enterprise as an investor-owned utility. The tax laws make investor-owned utilities revenue collectors for the government. Income taxes are not resource costs. Publicly-owned utilities own the same types of power resources, yet incur no tax expense.

Subsidization of income taxes serves to confer on investor-owned utilities the tax advantages of publicly owned utilities. This extra benefit goes far beyond the purpose of the residential exchange intended by Congress. The exchange should not be a vehicle for redistributing tax burdens from exchanging utilities to BPA's other customers (including publicly owned preference customers) or to the Federal Treasury (to the extent BPA rates fail to recover the full cost of the residential exchange subsidy).[11]

If federal and state income taxes are included in ASC, income taxes imposed on private utilities and not on public utilities would be spread to all BPA ratepayers regardless of their tax status.[12] State income taxes imposed in one jurisdiction and not in another, or imposed at varying rates, would be redistributed to all BPA ratepayers in the region. If normalized taxes were allowed in ASC, income taxes might be permanently shifted to BPA's customers from participating utilities. This is because participating utilities have 'a unilateral right to "deem" out of the exchange when actual taxes exceed normalized taxes. (*See* R. 1408.)

Under the 1981 methodology, BPA has dealt with a revenue related state tax seemingly tailor-made for regionalization through the residential exchange. Idaho Power Co. attempted to include in ASC the so-called Idaho "KWH tax." Section 63-2701 of the Idaho Code. Exceptions and exemptions in the Idaho KWH tax remove the requirement of payment from many, if not all, of the affected electric utility's commercial and manufacturing customers. That is, the tax almost exclusively applies to the retail customers whose rates are subsidized under the residential exchange. BPA's treatment of this tax is now pending FERC review in Docket No. ER83-687-000.

Legal precedent on "resource" costs support the conclusion that income and revenue-related taxes should be excluded from ASC. In 1976, the Federal Power Commission (FPC) was required by the Alaska Natural Gas Transportation Act, 15 U.S.C. §719, et seq., to perform a type of cost/benefit analysis on various pipeline proposals. In its consideration of the "Net National Economic Benefits" of the various proposals for an Alaskan gas pipeline, the FPC held that income taxes were not costs of resources:

> United States <u>income taxes are excluded on the grounds they are transfer payments rather than true resource costs</u>… Taxes other than income (*e.g.*, property taxes) are included on the grounds that they are a proxy for the costs of governmental services (*e.g.*, roads, health systems and schools for construction workers and employees) required as a result of a system's construction. [58 F.P.C. 810, 927 (1977), footnote deleted, emphasis supplied.]

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[11] The Comptroller General, in ruling on a bid protest in which a private utility was underbid by a rural cooperative for a government contract to provide electric service, held that the government was not required to take into account income taxes the private utility would have paid if it had been awarded the contract. 43 Comp. Gen. 60, 62 (1963). He noted that "no provision is made in any statute or regulation for eliminating the competitive advantages that cooperatives ...are given by statute, nor are there any provisions for eliminating a tax advantage one offeror may have over another." *Id.* at 63. Although this decision relates to a contract award, the principle of the decision applies here. The purpose of the exchange under the Northwest Power Act is not to alter the tax advantages of publicly owned utilities, or to confer such benefits on private utilities.

[12] Courts have traditionally held that discrimination results when all of a utility's customers assume the burden of special taxes exacted by a particular taxing entity within the utility's service area. *See*, Priest, supra, at 54, 307-308; *Village of Maywood v. Illinois Commerce Comm'n*, 23 Ill, 2d 447, 452, 178 N.E. 2d 345, 348, 42 Pub. Util. Rep., 298, 301 (1961). FERC ordered a power company to eliminate from its cost of service a tax "add-back" not properly attributable to its wholesale customers. *Re New England Power Co.*, 2 FERC 161,106, 61,258 (1978).

The Commission built upon the findings of Administrative Law Judge Litt who found that "[t]reating U.S. income taxes as transfer payments rather than costs is consistent with existing economic philosophy, as evidenced in Robert Nathan's scholarly presentation on the subject." 58 F.P.C. at 1394. The FPC's distinction between income taxes and property taxes is the same distinction recognized by BPA in the ASC methodology adopted in this decision.

3. Decision

Relevant legal and policy analysis, plus the weight of public comments, suggest that income taxes should not be included in the calculation of ASC. BPA's decision to exclude income taxes from calculation of ASC does not mean that any investor-owned utility will not recover such expenses in rates for sales of electric power. BPA has simply determined that income taxes are not resource costs within the meaning of section 5(c) of the Northwest Power Act and, therefore, not includable in the residential exchange subsidy.

VI. DETERMINATION OF GENERATING RESOURCES INCLUDABLE IN THE COMPUTATION OF AVERAGE SYSTEM COST

A. Summary of Positions

In the ASC methodology proposal of February 3, 1984, costs of generating resources were to be included in the ASC calculation only if those costs were included in a utility's rate base for retail ratemaking purposes by at least one regulatory authority in the Pacific Northwest. The intent of this proposal was to exclude costs of generating resources used for off-system sales, *i.e.*, resources not used to serve retail (residential and small farm) loads. (BPA, R18; Meyer (BPA), R. 1861-1862, 1864). BPA proposed to credit revenue from off-system sales contract system costs.

The DSIs agreed. (DSIs, R. 26A). However, they suggest that BPA clarify whether the costs of resources serving retail loads may be exchanged if this entails development of cost of service/cost allocation methodologies. (DSIs, 26A-27A; Tanner, R. 1862, 1864-1865; Tanner, R. 809). The DSIs stress that all of an exchanging utility's resources (exclusive of those serving extraregional, or new large single loads) be included in ASC and that all of a utility's sales, including wholesale firm and nonfirm sales, should be credited against ASC, either by crediting kilowatthour sales against contract system load, or by crediting sales revenue against contract system cost. (DSIs, R. 27A; Tanner, R. 1875; DSIs, R. 835-836). Similar concerns were expressed by the Springfield Utility Board. (Banry, SUB, R. 162A).

The Western Washington PUDs (WWPUD) also proposed that costs and revenues associated with generation plant not included in a utility's retail rate base by at least one retail rate regulator should be excluded from the ASC calculation (R. 542-566).

The Pacific Northwest Generating Company (PNGC) commented that BPA's initial proposal on generating resources should be clarified, and questioned whether the intent of the proposal is to allow a generating resource that finds its way into rates in one form or another is to be exchanged. (R. 538-539).

Several investor-owned utilities commented that the February 3 proposal does not explain how BPA would determine what generating resources would be included in ASC and could cause major uncertainty for exchanging utilities. (PGE, R. 702, 709; PP&L, R. 482-493; IPC, R. 633-638, 639). These commenters claim that BPA's February 3 proposal is inconsistent with the objective of using actual data as represented by the FERC Form 1 which includes secondary sales revenue. (WWP, R. 497, 504; MPC, R. 644, 647). The investor-owned utilities also express concern that BPA is willing to include secondary sales revenues which reduces ASC, but is not willing to include the corresponding generation costs (*e.g.*, PGE, R.702, 709).

The Oregon Public Utility Commissioner amplified on these comments by suggesting that BPA clarify the ground rules for determining what constitutes a resource dedicated to secondary load. (R. 164A, 172A). OPUC points out that BPA has surplus firm capacity exceeding the capacity of WPPSS No. 2, implying that WPPSS No. 2 is available for secondary sales and might therefore not be included in the priority firm rate. *Id.*

The Public Generating Pool contends that excluding costs of generating units used exclusively for the production of secondary energy is short-sighted since resources are not built exclusively for the production of nonfirm energy (R. 514, 516).

B. Discussion of Positions And Decision

BPA's proposal to exclude the costs of generating resources used for off-system sales was a necessary corollary to the uniform costing (FERC Form 1) approach to calculating ASC. Now that BPA has decided to retain the jurisdictional costing approach instead, this issue becomes moot. Virtually all parties submitting comments for the record believed that state regulatory commissions can be relied upon to determine what constitutes proper generating resources includable in ASC. Therefore, special criteria for identifying how generating resource costs should be treated in the ASC calculation are no longer required.

Retail rate orders will continue to be the primary source of data on generating resources. However, where necessary, BPA will independently determine costs (including costs of generating resources) for inclusion in ASC under the jurisdictional costing approach. The costs of any generating resource improperly included in a utility's ASC filing will be excluded from the ASC calculation.

VII. TREATMENT OF AFFILIATED FUEL COSTS IN CALCULATING ASC

A. Summary Of Positions

Under the uniform costing approach proposed by BPA, fuel costs included in the ASC determination would normally have been derived from FERC Form 1. However, special criteria were proposed for instances where the participating utility acquires fuel from a corporate affiliate

(R. 19-20). BPA defined "corporate affiliate" as a parent or subsidiary corporation, a fuel trust that to any degree is owned or controlled by a participating utility, or a corporation that has a parent corporation in common with a participating utility. Affiliate transactions are not characterized by arm's-length bargaining. The natural incentive of both parties to such transactions is to maximize the seller's profit. BPA was concerned that the residential exchange could become a means for passing excessive profits on to affiliates of participating utilities.

In expressing concern about affiliate fuel transactions, BPA followed the lead of FERC (and its predecessor the Federal Power Commission) which has long held that such costs warrant special scrutiny. *Montana Power Co.*, 4 FPC 213 (1945); and *Pacific Power & Light Co.*, 3 FPC 329 (1942). The FPC was not bound by the pricing provisions of affiliate contracts; an independent determination of costs was authorized. *Safe Harbor Water Power Corp.*, 1 FPC 230, 237-40 (1940).

In *Federal Register* notice of February 3, 1984, BPA proposed to calculate ASC of a participating utility with a fuel affiliate based on the lowest unit fuel cost allowed by that utility's regulators or, if lower, the unit cost contained in its FERC Form 1 or equivalent document (R. 19-20). This variant of the jurisdictional costing approach would ensure that any inflated fuel prices charged by affiliates were not included in ASC.

Pacific Power & Light commented on this proposal by noting that the cost data used by different regulators is from different test years. Therefore, comparisons between regulators are invalid. (R. 482-494).

Washington Water Power stated that the parent utility may be only one of several entities buying fuel from the affiliate. Sufficient safeguards exist in the agreements with the other utilities. (R. 497, 504-505).

Commenter Hemingway stated that BPA's method achieved a low result, but not necessarily an accurate one. The decisions of regulators who give the most attention to affiliated fuel costs could be disregarded under the BPA proposal. (R. 600, 607).

B. Discussion of Positions And Decision

BPA was initially concerned that the fuel costs shown in FERC Form 1 might be inflated for purchases from affiliates. Comparing the FERC Form 1 fuel costs with the fuel costs approved by regulators was selected as a reasonable method of checking the Form 1 costs. Since BPA has decided to retain the costs approved by the regulatory commissions as the source for costs includable in ASC, this issue has become moot. However, BPA still retains the right to examine the affiliated fuel costs approved by regulatory agencies, and determine if they are appropriate for calculating ASC.

VIII. CONSERVATION COSTS INCLUDABLE IN THE CALCULATION OF ASC

A. Summary Of Positions

BPA Review. BPA proposed to include conservation costs, subject to two limitations. First, such costs had to be incurred as part of a program that is consistent in terms of cost and timing, with the conservation plan developed by the Pacific Northwest Electric Power and Conservation Planning Council. Second, conservation costs incurred pursuant to model standards included in the Council Plan, as required by section 4(f)(1) of the Northwest Power Act, were not includable in ASC.

Pacific Power & Light Co. and Puget Sound Power & Light Co. objected to this BPA approval authority. They state BPA could use the approval authority to force the utilities to sign BPA's long-term conservation contracts, which may not be cost-based. (PP&L, R. 462, 493; Puget, R. 620, 628).

Other investor-owned utilities commented that their conservation programs were developed in cooperation with, and approved by, state regulators. Under the BPA proposal, BPA could exclude these locally designed programs, even though they are' cost-effective. (IPC, R. 633, 639; WWP, R. 497-505).

Puget Sound Power & Light objected to excluding from ASC the costs of meeting model standards. (R. 620, 628). Excluding these costs discourages the utility from implementing the Regional Council's plan. One commenter stated that this would provide a disincentive to utilities that take a leadership role in establishing model standards. (Utah Power & Light, R. 612, 617).

The Washington Utilities and Transportation Commission commented that disallowing costs incurred to promote conservation hinders the utility's ability to achieve the level of conservation envisioned by the Regional Council. (R. 698, 700).

The Western Washington PUDS stated that BPA's proposal could be interpreted to mean only BPA conservation programs will be approved. (Mundorf, WWPUD, R. 1895-1896). The PUDs argue that the Regional Council's plan is designed to meet the energy needs of the Northwest as a whole, and is not designed to be utility specific. A utility with relatively high load growth may require more conservation than the Regional plan calls for, because conservation is the cheapest resource available to meet that load growth. Yet BPA could disallow the conservation costs above what the Regional Council's plan calls for, even though the utility is seeking to minimize costs. (Mundorf, WPPUD, R. 1911-1912).

Conservation-Related A&G Expenses. BPA's initial proposal did not specifically address the question of whether conservation administrative and general (A&G) expenses be allowed in determining ASC. The DSIs argue, however, that A&G expenses are not resource costs, and should not be used to calculate ASC. Only costs of physical improvements which produce a measurable reduction in load should be allowed in ASC. (R. IA, 28A-29A; Wilcox, DSI, R. 1924). Costs incurred to promote changes in consumer behavior should be excluded, since the consumer makes the change, not the utility. (Wilcox, DSI, R. 1901). Some parties have questioned whether advertisements that promote conservation but contain the utility's name are promoting goodwill for the utility as much as promoting conservation.

Utah Power & Light argues that the A&G costs must be incurred to achieve conservation. Similar costs are included in the PF rate, and they should therefore be allowed in the ASC. (UP&L, R. 6578).

The WWPUDs claimed that costs of conservation audits should be included in ASC. The audit causes the customer to install the physical improvements. (Hutchison, WWPUD, R. 2674-2675). However, BPA pays for the audit where the customer participates in BPA-sponsored conservation programs. (Hutchison, WWPUD, R. 2679). The utility only pays for audits in which the consumer purchases the conservation measures themselves or performs no conservation. Unfortunately BPA cannot differentiate between audits which induce no conservation and those which lead to the consumer paying for the conservation measures themselves. (Meyer, BPA, R. 2737).

BPA's proposal would allow the BPA conservation contract charge in determining ASC. (Meyer, BPA, R. 1893-94.) The Public Power Council argued that the contract charge should not be exchangeable. The Council states that the contract charge reflects an 1983 rate case cost allocation that assumes the utility is not exchanging those costs. (PPC, R. 528).

Billing Credits. The Western Washington PUDs also state that all billing credits paid by BPA to regional utilities should be used as an offset to reduce an exchanging utility's ASC. (Hutchison, WWPUD, R. 1934). The WWPUDs state that most utilities will receive billing credits for rate design measures. (Mundorf, WWPUD R. 1934). Utilities can implement these rate designs at low cost, and receive large billing credits from BPA that may greatly exceed the costs of the program. (Wilcox, DSI, R. 1938). Even if the entire billing credit revenue is used as an offset, the utility's ratepayers still get the benefits of the billing credit. Failure to offset gives the utility a windfall. (Wilcox, DSI, R. 1939).

Pacific Power & Light Co. favors limiting the billing credit revenues credited against Contract System Cost to the cost of the measure. PP&L claims that reducing ASC by any amount of billing credits greater than the cost of the measure transfers the billing credit revenues to customers served by Exchange resources. (PP&L, R. 6696.) It then presents an example to show that non-Exchange and Exchange utilities are treated differently when the revenue credit exceeds the cost of the program. (PP&L, R. 6703).

B. Discussion Of Positions And Decision

Regulatory commissions review investor-owned utility conservation programs and disallow those costs that are not prudently incurred. Similarly, the governing bodies of the publicly owned utilities set levels o€ conservation expenditures (Ailshie, BPA, R. 1919). However, rate regulators use guidelines that differ from those used to determine what costs should be subsidized under the residential exchange (Ailshie, BPA, R. 1921). Also, in some instances, regulators may approve a total expense number for a whole range of accounts, leaving it to the utility to determine how to spend the money (McPhail, DSI, R. 1920). BPA still has the statutory obligation to ensure that impermissible costs are not allowed in ASC (Mundorf, WWPUD, R. 1922).

The Administrator will determine what conservation costs are allowable in ASC. Of necessity, these determinations must be case specific, based on the information provided by the exchanging utility in its ASC filing. As a general proposition, however, if a utility accelerates or postpones implementing one of the Regional Council's programs, the cost of the program may be higher than if the utility followed the Council's plan. Under the methodology adopted in this decision, the utility would pay the higher costs, not BPA's ratepayers. (Meyer, BPA, R. 1910; Ailshie, BPA, R. 2495-96).

Model conservation standards are mandated by Section 4(f)(1) of the Regional Act. Section 4(f)(2) of the Northwest Power Act gives, the Regional Council and the Administrator the authority to impose a surcharge on customers for those portions of their loads which have not achieved energy savings comparable to those which would be obtained under the standards. Therefore, the utilities must implement the model standards or pay the surcharge. Disallowing model standards costs from ASC does not discourage utilities from implementing the Council's plan. Permitting inclusion of the surcharge in ASC would destroy the very purpose of that surcharge.

The utility may also promote a particular housing development with all-electric heating that has met the standards. Thus, the utility can use the model standards to promote load growth. (Meyer, BPA, R. 1899). Promoting electricity consumption is not a conservation cost and therefore, not a resource cost.

In implementing the standards, the utility is not actively purchasing resources, but merely ensuring that the model standards are being met. Therefore, model standards costs are not resource costs. (Meyer, BPA, R. 1897-1896).

Conservation A&C expenses will be limited to only those expenses relating to conservation measures for which power is saved by physical improvements or devices. Advertising, promotion, and audit expenses are not resource costs and therefore are not includable in the ASC.

The purpose of the conservation-contract charge is to ensure an equitable allocation of BPA conservation costs between generating and non-generating utilities. BPA's conservation allocation method in the 1983 rate case assumed that the contract charge was an exchangeable cost. E-BPA-A-02, 142. Therefore, allowing the contract charge in ASC does not distort the allocation used in the 1983 rate case. (Mundorf, WWPUD, R. 1894). BPA will allow the conservation contract charge in ASC. This does not distort the allocation used in the 1983 rate case.

The offset against ASC will include all revenues arising from billing credits. The utility still receives the billing credit and its ratepayers receive the benefits of the credit. It is also consistent with how BPA treats the cost of other resource acquisitions.[13]

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[13] Pacific Power & Light's analysis is flawed for several reasons. First, it assumes that the utilities serve only residential and small farm loads. It is this assumption which forces the utility to repay its entire billing credit. Actually, the utility only returns the percent of the credit that makes up its residential and small farm load. Second, it

IX. FUNCTIONALIZATION BETWEEN SUBSIDIZED AND NONSUBSIDIZED ACCOUNTS

A. Summary of Positions

The 1981 methodology incorporates a three-part functionalization approach: (1) the 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. BPA proposed to eliminate the third approach ("footnote 24" in the 1981 methodology) in its proposal of February 3, 1984. The functionalization produced by application of footnote 24 has been very imprecise. BPA would rely exclusively on the remaining two functionalization methods. (*See* Meyer, BPA, R. 1940-41.)

The Western Washington PUDs support the elimination of Footnote 24 (R. 546, 572; Mundorf, WWPUD, R. 2255; R. 739, 759). According to the PUDs, all exchangeable costs should be functionalized by direct assignment, with administrative and general expenses and similar cost items functionalized on the basis of the utility's labor ratios (R. 546, 572; Hutchison, WWPUD, R. 1943).

The DSIs support elimination of Footnote 24 in their comments (R. 6A; 43A; 133A). However, the DSIs assert that BPA's reliance on analytical studies and/or direct functionalization may permit the exchange of non-resource costs and create unverifiable studies skewed toward subsidized cost categories (R. 6A; 43A-46A., 135A-138A). Instead, the DSIs recommend reliance on direct assignment of costs, with use of existing Footnote 13 (labor ratios) for costs that cannot be directly functionalized (R. 6A; 43A-46A; 138A-140A; Schoenbeck, DSI, R. 1944-1946).

The DSIs further propose that a number of different ratio allocators be adopted to lessen arguments over how accounts would be functionalized given the diverse interpretations that exist under the present methodology. (Schoenbeck, DSI, R. 1945-46).

The Pacific Northwest Generation Company objects to the elimination of Footnote 24 (R. 540, 721, 1942). Forcing exchanging utilities to justify costs through direct functionalization is an unnecessary burden requiring a great deal of time (R. 540, 2485). Instead of direct functionalization, the PNGC proposes that BPA retain the 1981 methodology with the exception of Footnote 3, and not permit the direct functionalization of any costs governed by these footnotes (R. 540).

Generally, the proposed elimination of Footnote 24 for allocating costs was opposed by investor-owned utility commenters (PGE, R. 712; PP&L, R. 495; WWP, R. 507; Puget, R. 630; MPC, R". 649). The IOUs assert that Footnote 24 was developed in 1981 as a reasonable

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assumes that all utilities receive the same per-unit billing credits. Those utilities receiving lower per-unit billing credits pay part of the billing credits of the other utilities. Therefore, the.exchanging utility will never return its entire billing credit to BPA.

method for allocating general costs and that there is no reason to change (*e.g.*, MPC, R. 649). The IOUs further contend that replacing Footnote 24 with direct functionalization would force a utility to establish burdensome internal budgeting and accounting procedures to functionalize costs more directly, or forego their inclusion in ASC (PGE, R. 713; PP&L, R. 495; WWP, R. 507; Puget, R. 630).

Additionally, some IOUs contend in their comments on the BPA proposal that BPA has provided no criteria under the direct functionalization method, giving BPA discretion to reject filed costs in their entirety. (UP&L, R. 617; Puget, R. 626). They maintain that this would allow BPA to be arbitrary in reviewing a utility's direct analysis. (UP&L, R. 625).

The Public Generating Pool suggests that the current functionalization approach may be reasonable if Footnote 24 is either eliminated or tightened up (R. 515).

The Public Power Council suggests that BPA consider measures to restrict abuse of the functionalization process. To prevent abuses, the PPC suggests that BPA require that an exchanging utility to certify that no studies have been performed that would show a lower ASC for an item functionalized under Footnote 24 (R. 371). The PPC also supports BPA's proposal to eliminate Footnote 24, and the use of direct functionalization wherever possible (R. 6671).

The Public Utility Commissioner of Oregon notes that Footnote 24 was developed as a reasonable method of allocating costs of a general corporate nature, and an approach using individually determined techniques will lead to a morass of unnecessary studies and paperwork which is contrary to BPA's goal of minimizing the administrative burden of the ASC review process. (R. 173A).

The Salmon River Electric Cooperative discusses the use of labor ratios as a substitute for Footnote 24, especially for the functionalization of some utility expense items which cannot be directly functionalized (R. 663). However, SREC suggests that BPA develop standard formulae to aid in functionalizing certain costs (R. 664).

B. Discussion of Positions

BPA proposed to eliminate Footnote 24 since it was an imprecise method of treating exchangeable production and transmission costs. BPA agrees with many of the commenters[**] that the application of footnote 24 has led to the inclusion of non-resource related costs. As a result, BPA proposed the use of direct analysis according to the FERC Uniform System of Accounts as the only option available for functionalizing costs under the initial ASC methodology proposal.

However, PNCC assertions that eliminating Footnote 24 and requiring direct analysis could create excessive burdens has merit, at least in some instances. BPA also acknowledges the claim by the IOUs noted above, and WWPUD, that forcing the use of direct analysis could eliminate certain resource costs that are too difficult to functionalize by a detailed study (WWPUD, R. 572).

The parties' reply comments reveal conflicting positions on functionalization. For example, WWPUD contends that the proposed use of labor ratios to functionalize certain costs such as miscellaneous production costs is improper because miscellaneous production costs are not labor-related. The DSI proposal would require that BPA disregard the fact that the relevant FERC accounts directly functionalize these costs (WWPUD, R. 761).

The DSIs disagree with the IOU assertion that Footnote 24 is a reasonable approach since Footnote 24 has permitted abuse (R. *32). On the other hand, the DSIs agree with the IOU claim that direct cost assignment through functionalization studies would be an expensive and inefficient process, and BPA could consequently find administration of the exchange more complex and controversial than under the present approach (R. 833).

C. Decision

Although BPA will rely on total costs approved by state regulatory commissions, these total costs must still be separated into the production, transmission and distribution/other functions required for the calculation of ASC. Only properly determined costs should be categorized into the production and transmission functions as allowed by the ASC methodology. Therefore, BPA will use the two cost functionalization methods specified in the BPA proposal, with some minor modifications.

These two methods (discussed below) entail the choice between direct analysis or specific functionalization ratios applied to the various FERC accounts (the so-called "cookbook method"), and functionalization required by FERC accounts. Adoption of the direct analysis and cookbook methods has the major support of the parties participating in the consultation proceeding. These methods should serve to mitigate significant cost assignment abuses inherent in the existing ASC Methodology, such as changing functionalization methods from filing to filing and the inclusion of improper costs in ASC. BPA retains the authority to review and accept only those functionalized costs it deems appropriate for exchange transactions, as it did under the previous ASC methodology.

An exchanging utility will not be permitted to switch back and forth between the functionalization methods without prior written approval from BPA. The final functionalization methods are described in detail below.

FUNCTIONALIZATION METHODS:

A. By direct analysis which assigns costs to either the production, transmission, or distribution function of the utility. Such analysis is subject to BPA review and approval. This option allows a utility to assign costs to, production, transmission and distribution/other when it has sufficient data available demonstrating that such cost assignment is appropriate. Therefore, the utility is permitted flexibility in its ASC functionalization design while BPA retains discretion to review and approve how these costs are assigned. The utility must submit with its ASC filing any and all workpapers, documents, or other materials demonstrating that the functionalization under its direct analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation will result in-the entire account being functionalized to Distribution/Other.[14]

B. According to the following specific functionalization methods by FERC account as shown below. The FERC Uniform System of Accounts is still used for a large number of the exchange utilities' rate base costs and expenses. This option represents a significant shift away from the single direct-analysis method presented in BPA's initial proposal, and should provide a reasonable alternative to functionalizing certain cost items under the direct analysis method which may be too burdensome for some utilities.

ACCOUNT FUNCTIONALIZATION METHOD

I. RATE BASE ACCOUNTS:

310-373 (Plant in Service)	Functionalize directly according to the Federal Energy Regulatory Commission System of Accounts.
389 (Land and Land Rights)	Functionalize on the ratios of Production, Transmission and Distribution Gross Plant excluding General Plant.
390 (Structures and Improvements)	Functionalize on the ratios of Production, Transmission and Distribution Gross Plant excluding General Plant.
391 (Office Furniture and Equipment)	Labor ratios.
392 (Transportation Equipment)	Functionalize on the ratio of Transmission and Distribution Gross Plant excluding General Plant.
393 (Stores Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
394 (Tools, Shop and Garage Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
395 (Laboratory Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
396	Functionalize on the ratio of Transmission and

[14] To ameliorate the concerns raised by the PNGC, BPA will continue allowing certain plant account costs (389, 390, 391 and 392) and administrative and general expense account costs (920 and 921, 922, 930.2 and 932) to be functionalized by the following three options, whichever assigns the highest cost to the production and transmission functions: (1) direct analysis, (2) the specific functionalization ratios discussed next, or (3) for publicly-owned and cooperative utilities that have neither generation facilities nor affiliated generation organizations over which the utility exercises over half of the voting rights, 10 percent of gross plant investment may be assigned directly to Production and 10 percent of labor costs assigned to Production. The remainder of accounts 389, 390, 391, and 392 will be functionalized using Transmission and Distribution Gross Plant Ratios excluding General Plant-The remainder of Accounts 920, 921, 922, 930.2 and 932 will be functionalized using the Labor Ratio for Transmission and Distribution, and the balance assigned to Distribution/Other.

(Power Operated Equipment)	Distribution Gross Plant excluding General Plant.
397 (Communication Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
398 (Miscellaneous Equipment)	Functionalize** to Distribution/Other.
399 (Other Tangible Property)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
301-303 (Intangible Plant)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
114 (Acquisition Adjustment)	Labor Ratios.
105 (Plant Held for Future Use)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant including General Plant.
120.2-120.4 less 120.5 (Nuclear Fuel)	Functionalize to Production.
186 (Miscellaneous Debits)	Labor Ratios.
252 (Customer Advances)	Functionalize to Distribution/Other
257 (Unamortized Gain Reacquired Debt)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant including on General Plant.
151-152 (Fuel Stock)	Functionalize to Production.
153-157, 163 (Materials and Supplies)	Functionalize on the ratio of Transmission and Distribution Gross Plant including General Plant.
106 (Completed Construction not Classified)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
124 (Other Investment)	Functionalize to Distribution/Other.
184 (Clearing Accounts)	Labor Ratios
Other Rate Base	Functionalize to Distribution/Other.

Accounts	

2. **EXPENSE ACCOUNTS:**

501-577 (Fuel, Purchased Power and Power Production** Expenses)	Functionalize to Production.
560-573 (Transmission Expenses)	Functionalize to Transmission.
580-598 (Distribution Expenses)	Functionalize to Distribution/Other.
901-905 (Customer Accounts Expenses)	Functionalize to Distribution/Other.
907 (Customer Service Information Expenses-Supervision)	Functionalize to Distribution/Other.
908-910 (Other Customer Service Information Expenses)	Functionalize to Distribution/Other.
911-916 (Sales Expenses)	Functionalize to Distribution/Other.
920 (Administrative & General Salaries)	Labor Ratios.
921 (Office Supplies & Expenses)	Labor Ratios.
922 (Administrative Expenses Transferred-Cr.)	Labor Ratios.
923 (Outside Services Employed)	Labor Ratios.
924 (Property Insurance)	Functionalize on the ratio of Production, Transmission, and Distribution Gross Plant including General Plant.
925	Labor Ratios.

(Injuries & Damages)	
926 (Employee Pensions & Benefits)	Labor Ratios.
927 (Franchise Requirements)	Functionalize to Distribution%Other.
928 (Regulatory Comm. Fees & Expenses)	Functionalize to Distribution/Other
929 (Duplicate Charges-Cr.)	Labor Ratios.
930.1 (General Advertising)	Functionalize to Distribution/Other.
930.2 (Miscellaneous General Expenses)	Functionalize to Distribution/Other.
931 (Rents)	Functionalize to Distribution/Other.

3. REVENUE ACCOUNTS:

447 (Sales For Resale)	Functionalize to Production.
450-455 (Other Operating Revenues)	Functionalize to Production.
456 (Wheeling Revenues)	Functionalize to Transmission.

C. THE FOLLOWING ACCOUNTS SHALL BE FUNCTIONALIZED AS FOLLOWS:

107, 120.1 (CWIP)	Functionalize to Distribution/Other.
108 (PIS Depreciation Reserve)	The same functionalization used for accounts 310-373, Plant in Service (PIS).
108 (General Plant Depreciation Reserve)	Functionalize according to the General Plant ratio.
111	The same functionalization used for accounts 301-303,

(Accumulated Amortization)	Intangible Plant.
256 (Deferred Gain from Disposition of Utility Plant)	The same functionalization used for account 105, Electric Plant Held for Future Use.
403-407 (PIS Depreciation Expense)	The same functionalization used for Accounts 310-373, Plant in Service.
408.1 (Other Taxes)	With the exception of property taxes and labor related taxes, all taxes will be functionalized to Distribution/Other. Property taxes will be functionalized using the gross plant ratio including general plant. Labor related taxes will be functionalized using labor ratios.
409.1, 410.1, 411.1, 411.4 (Income Taxes)	Functionalize to Distribution/Other.
932 (Maintenance of General Plant)	Functionalize according to the ratio developed from the functionalized totals of accounts 390, 391, 397 and 398.
411.6, 411.7 (Gain from Disposition of Utility Plant)	The same functionalization used for Account 105, Plant Held for Future Use.

CHAPTER FIVE

BPA REVIEW PROCEDURES

A. Summary Of Proposals

BPA proposed to simplify its review procedures. Deficient filings would be rejected and the new ASC would not be applicable until a proper filing was received by BPA. To facilitate proper filings, BPA offered the opportunity for prefiling conferences with exchanging utilities** where differences could be resolved prior to filing.

During the negotiation sessions, the parties arrived at a general consensus that BPA should play a more active role in ascertaining whether ASC filings contain legitimate resource costs eligible for the exchange. Although jurisdictional cost data will still be used, it simply provides the starting point for BPA's review process.

The review procedures that were included in BPA's staff proposal on May 15, 1984, reflect concerns raised during the consultation sessions and the experience gained by BPA staff during two years of exchange program administration. The major changes to, the current procedures were necessary to implement the more active nature of BPA's review as well as to bring somewhat more formality to the review process.

While not participating in the negotiation sessions held on April 20, 23-27, 30 and May 1-4, 1984,' investor-owned utility commenters have opposed a more active role by BPA during the review process. (PP&L, R. 6684-6685; PGE, R. 6709; UP&L, R. 6575; IPC, R. 6660-6661). The public utility commissions for the state of Washington, Idaho and Oregon have taken positions similar to the private utilities. Both the private utilities and the state commissions note that BPA is not precluded from participating in the state retail rate proceedings.

On May 25, 1984, BPA received a number of comments regarding its proposed rule for the review process. BPA's rule for its review process incorporates a number of the suggestions raised by various parties.

B. Decision

Several commenters assert that BPA's review procedures are not changeable parts of the ASC methodology. They claim instead that these procedures are fixed by BPA's Residential Sales and Purchase Agreement with exchanging utilities, Contract No. DE-MS79-83BP9. *See* UP&L, R. 6575). This is incorrect.

The ASC methodology is comprised of a number of sections, including both BPA procedures and FERC procedures. FERC's interim regulations included the BPA procedures. *See* 18 C.F.R. sec135.13a (1983 ed.). In its final rule, however, FERC excluded the BPA procedures, noting that the procedures are a BPA rule, and that the parties should raise their concerns over BPA procedures with BPA.

The 1981 ASC methodology, including both BPA and FERC procedures, was merely incorporated in the Residential Sale and Purchase Agreement for ease of reference. The methodology, which was adopted by the Administrator at the end of a statutory process, antedates the contract. Section VI of the 1981 methodology provides for changes in the methodology, including the BPA procedural components thereof. BPA's procedures are a BPA rule which is subject to change when the Administrator finds it necessary to do so.

BPA has determined that the responsibility placed on it by the Northwest Power Act mandates a more active role. BPA acknowledges that a more active role in the review process may not decrease the amount of controversy[**] surrounding BPA's review of ASC filings. (*See* Puget, R. 6570-6571; PP&L, R. 6685-6686). In addition, BPA recognizes that the revised procedures may require more time to administer than the current review procedures. *See* Puget, R. 6571; PP&L, R. 6683-6685). The concerns raised by the investor-owned utility commenters are the necessary result of BPA's expanded role in reviewing the costs included in the average system cost filings.

A description of the revisions to BPA's review procedures follows.

<u>Subsection III.D.1</u>, which defines parties, has been revised to require that persons accorded party status demonstrate an interest in the outcome of the BPA review. In the review process, persons accorded party status have substantial rights including the right to request data from the utility. *See* subsection III.D.2. The ability to obtain confidential or proprietary data should be limited to persons with an economic and financial interest in the process. (*See* PP&L, R. 6694). Generally, customers of BPA will have the right to intervene; however, retail customers of BPA wholesale customers may not be able to demonstrate an unrepresented interest so long as their utility has intervened. *See*, *e.g.*, Durham, R. PGE. All other provisions of BPA's Review Procedures that are affected have been revised accordingly.

<u>Section I.J</u>, which defines "Test Period", has been revised to use a test period consistent with the one used by the retail rate regulator in setting rates upon which the ASC filing is based. There is a proviso, however. The test period will not be less than twelve months. Using less than a twelve month test period for determining the costs used to compute average system cost would not adequately reflect the variation in the loads and costs that occur. This would not reflect the true cost of resources for the filing utility.

<u>Section I.L</u>, which defines when an Appendix l is "filed", has been modified to allow the utility to hand deliver the Appendix I to BPA's Division of Financial Requirements in Portland. The limitation on mailings was provided as a convenience to the utilities submitting an ASC filing. The modification, however, limits the time for hand delivery to normal business hours, 8 AM to 5 PM. BPA recognizes that some of the utilities may prefer to hand deliver the Appendix 1. This modification was requested by PP&L. (R. 6692). May 25, 1984) p. 19. BPA, however, retains the certified mailing requirement. It is the responsibility of the utility to ensure that BPA receives the utility's Appendix 1. Section I.L has been further modified to reflect this responsibility by requiring that BPA receive the Appendix 1 before it is considered filed. The return receipt will be evidence that the filing has been made.

Section IV, which states the Administrator's procedures for revising the ASC methodology, has been modified to clarify the original intent of section VI of the 1981 methodology. In addition, initiation[**] of the consultation proceeding is made discretionary, rather than mandatory. This modification ensures that BPA is not required to initiate[**] a process that it believes unnecessary.

Length of Review. BPA's original proposal included a variable review period that ranged from 130 days to 200 days depending on the circumstances. (*See* Exhibit 2 to Transcripts, R. 1160). As a result of public discussions with the parties and for administrative convenience, BPA Staff proposed a fixed determination date. BPA recognizes that the longer review period could present a greater financial risk to the utility. (*See* IPC, R. 6661- 6662; PP&L, R. 6685-6686). However, BPA's experience has shown that for complex issues an extended period of time may be required.

For example, *BPA's Average System Cost Report for Portland General Electric Company* (May 13, 1983), which resulted in the exclusion of terminated plant costs from ASC, required approximately 200 days to complete. In addition, BPA's decision to take a more active role in the review process necessitates allowing parties an opportunity to address issues that may not have been addressed in the retail rate process.

Under the 1981 methodology the comment period closes 100 days after the beginning of the Exchange Period. BPA then had 20 days to issue its final determination. Experience has shown that comments, especially from the DSIs, were submitted on the last day of the comment period. As a result, there have been many requests from utilities to be given an opportunity to respond to the comments. The new review procedures address this problem by requiring an early identification of the issues and give all parties an opportunity to comment and to reply to comments of other parties.

BPA believes that the review procedure is a reasonable balancing of the financial risk of the utilities and the need to provide sufficient time to carry out BPA's responsibilities[**] to review the average system cost filings of the utilities. BPA notes that some of the IOUs are concerned that the review period may run as long as 310 days. (*See*, *e.g.* PP&L, R. 6694). This is a misinterpretation. The extra 100 days which would result in a 300 day review period is applicable to only the initial filing under the new methodology. All other filings would be subject to the 210 day deadline.

BPA may challenge the load figures used by exchanging utilities in their ASC filings. *See* Section III.D.4. (*Contra, see* WWPUD, May 25, 1984; DSI, R. 6594-6654). BPA is aware that the costs in the jurisdictional proceedings are based on an assumed load and that the load may be related to many variables. (*See* PP&L, R. 6693-6694). BPA also acknowledges the complexity of any adjustment to loads and its effect of all related costs. Notwithstanding, BPA has a responsibility to examine the loads used since any change in the loads will have a direct effect on the average system cost.

In addition to the modifications specifically addressed above, there are additional minor modifications to tighten the procedures. These include (1) extending the holiday provision of

Section III.D to all deadlines (WWPUD, May 25, 1984); (2) changing the deadline for requesting oral argument and clarifying who can present oral argument (WWPUD, May 25, 1984, p. 26-27); (3) requiring service on all parties of all comments and cross comments (WWPUD, May 25, 1984, p. 25-26), (4) defining Initial Exchange Period (WWPUD, May 25, 1984); and (5) limiting Appendix 1 filings for jurisdictions subject to the exchange only (PP&L R. 6692).

Each exchanging utility is required to file under the new methodology within 20 days after implementation by FERC. Any utility failing to do so will have its ASC deemed equal to zero until compliance occurs. *See* methodology "Filing Procedures," section II.(B)(1)(a).

CHAPTER SIX

IMPLEMENTATION OF THE REFORMED METHODOLOGY

A. Summary Of Positions

Several commenters have suggested that the new ASC methodology be phased-in over a reasonably short period of time. “Phase-in” would minimize the retail rate effects of the change in methodology for the residential customers of exchanging utilities. In its proposal of May 15, 1984, BPA staff proposed that the new methodology be phased-in over the course of one year.

Under the staff phase-in proposal, the new methodology would be implemented by FERC on July 1, 1984, the date on which participating utilities qualify to exchange 90 percent of their residential loads under Section 5(c) of the Northwest Power Act. However, for the ensuing 12-month period, the actual ASC subsidy for each participating utility-could be determined as the average of the ASC in effect on July 1, 1984, and the ASC calculated under the new methodology.

On July 1, 1985, the new methodology would become the exclusive means of determining the ASC of each participating utility. July 1, 1985, is the date on which participating utilities qualify to exchange 100 percent of their residential loads.

Phase-in only affects the utilities currently “exchanging” with BPA. The six “deeming” investor-owned utilities will not be affected by phase-in, or by the new methodology for that matter.

Only the DSIs oppose this implementation proposal. After stating a number of objections, the DSIs propose a six-month phase-in instead. (R. 6592).

B. Decision

The ability to phase-in an ASC methodology is inherent in the discretionary authority granted the BPA Administrator by section5(c) of the Northwest Power Act. The purpose of the residential exchange subsidy is to provide rate relief to the residential customers of exchanging utilities. It would be anomalous[**] if the Administrator were not able to consider the effects of a change in methodology on these retail ratepayers. BPA will implement the new methodology according to the staff phase-in proposal, if FERC approves it.

Both the DSIs and various publicly owned utilities analyze the phase-in proposal from the perspective of the so-called DSI “floor rate.” The Northwest Power Act provides in section 7(c)(2), 16 U.S.C. §839e(c)(2), that “the Administrator’s rates [to the DSIs] during such period [after July 1, 1985] shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.” The DSI rates in effect during the relevant contract year vary according to the level of the residential exchange subsidy. The DSIs seek a low floor rate; the publicly owned utilities want it higher. Resolution of the floor rate question must await BPA’s 1985 general rate proceeding; the issue will not be decided now.

CHAPTER SEVEN

FINDINGS AND CONCLUSION

Following the consultation proceeding required by section 5(c)(7) of the Northwest Power Act, l6 U.S.C. §839c(c)(7), and in consideration of the foregoing discussion, the Administrator has determined to adopt the methodology set forth in this Record of Decision as the new administrative rule governing the calculation of the average system cost of resources for utilities participating in the residential exchange program. The methodology will now be submitted to the Federal Energy Regulatory Commission for review and approval in accordance with section 5(c)(7).

Issued in Portland, Oregon, June 4, 1984.

Peter T. Johnson
Administrator

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OFFICIAL RECORD
1984 AVERAGE SYSTEM COST
METHODOLOGY PROPOSAL
(BPA File No. ASC-83)

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

JUNE 1984

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1984 AVERAGE SYSTEM COST CONSULTATION

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Consultation session transcript, 4/26/84, Portland, Volume VI. 1974
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ABBREVIATIONS OF COMMENTING PARTIES

PARTY	ABBREVIATION
Bonneville Power Administration	BPA
CP National Corp.	CPN
Direct Service Industrial Customers	DSI
Idaho Cooperative Utilities Assoc.	ICUA
Idaho Power Co.	IPC
Idaho Public Utility Commissioner	IPUC
Investor owned utilities	IOU
Montana Power Co.	MPC
Oregon Public Utility Commissioner	OPUC
Pacific Northwest Generating Co.	PNGC
Pacific Power & Light Co.	PP&L
Portland General Electric Co.	PGE
Public Generating Pool	PGP
Public Power Council	PPC
Puget Sound Power & Light Co.	Puget
Salmon River Electric Cooperative	SREC
Springfield Utility Board	SUB
Utah Power s Light Co.	UP&L
Western Washington PUDs	WWPUD

DEPARTMENT OF ENERGY

BONNEVILLE POWER ADMINISTRATION

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

June 1984

CONTENTS:

REVIEW PROCEDURE

BONNEVILLE POWER ADMINISTRATION

The following rule sets forth the procedures by which an Average System Cost (ASC) filing is to be submitted to Bonneville Power Administration (BPA) and by which the BPA review process will be conducted. BPA's review is to determine the ASC for the purpose of the residential exchange between BPA and participating utilities pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839, *et. seq.* (Northwest Power Act).

I. DEFINITIONS:

For purposes of BPA's review procedures for Appendix 1, the following definitions apply:

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 the Federal Energy Regulatory Commission.

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 excluded from ASC by section 5(c)(7) of the Northwest Power Act.

D. "Contract System Load" means the firm energy load used by the State Commission for the purpose of establishing retail rates, adjusted pursuant to the Average System Cost Methodology rule.

E. "Costs" means the aggregate dollar amount or any portion of the amount allowed or relied upon by the State Commission to determine the test period revenue requirement for the Utility in a Jurisdiction.

F. "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 Agreement. For the purposes of any initial Appendix 1 filing' the Exchange Period shall commence on the date such Appendix 1 is filed and end with the effective date of the next retail rate change.

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

H. “New Large Single Load” means that load defined in section 3(13) of the Northwest Power Act, and as determined by BPA as specified in power sales contracts with its customers.

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

J. “Test Period” means the time period (not less than 12 months) used by the State Commission to determine Costs for retail ratemaking.

K. “State Commission” means a state regulatory body, preference utility governing body’ or other entity authorized to establish retail electric rates in a Jurisdiction.

L. “File” or “Filed” means that the Appendix 1 has been:
   (1) hand delivered to the Division of Financial Requirements; Bonneville Power Administration; Portland, Oregon; or
   (2) mailed to BPA by certified mail, return receipt requested, to the following address:

   Bonneville Power Administration
   Division of Financial Requirements Routing: DN
   P.O. Box 3621
   Portland, Oregon 97208

   and has been received by BPA. An Appendix 1 shall be considered to be filed as of the date of the postmark on the certified mailing.

M. “Review Period” means that period of time during which a Utility’s Appendix 1 is under review by Bonneville. The review period begins when an Appendix 1 is Filed and ends two hundred and ten (210) days after the Utility Filed its Appendix 1.

II. FILING PROCEDURES:

The procedures set forth in this section state the filing requirements for all Utilities which File an Appendix 1. 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.

B. For each Exchange Period and for each regional Jurisdiction in which a Utility provides service’ the Utility shall complete and File three copies¬of Appendix 1 as follows:

1. (a) Within twenty (20) working days after the date the Commission grants interim approval, or final approval in the event no interim approval is granted to any revised ASC Methodology, the Utility shall File an Appendix 1, which includes a loss study' reflecting its Costs for the test period for the rate schedule(s) then in effect for each Jurisdiction. Subject to the provisions of section III, the ASC determined from each Appendix 1 shall be the rate applicable to exchange power from that Jurisdiction during the initial Exchange Period. For purposes of this subsection, the initial Exchange Period shall commence on the date the Commission grants interim approval, or final approval in the event no interim approval is granted to any revised Methodology; provided that if a Utility Files an initial Appendix 1 after the twenty-day deadline' BPA may make the new ASC payable only from the date the initial Appendix 1 was actually Filed. However, BPA shall not delay as a result of a late filing of an Appendix 1, the effective date of any change in the ASC if the late filing was the result of unavoidable delay or excusable neglect, and the Utility proceeded to File its initial Appendix 1 as soon as practicable. If a Utility fails to File its initial Appendix 1 within the twenty-day deadline, the ASC of that Utility for the initial Exchange Period shall be zero (0) until the Utility files its initial Appendix 1.

   (b) For those Utilities that are parties to an Exchange Transmission Credit Agreement (ETCA), within twenty (20) working days after the date the ETCA is terminated, the Utility shall File an Appendix 1, which includes a loss study, reflecting its Costs for the Test Period for the rate schedule then in effect for each Jurisdiction. Subject to the provisions of section III of this rule, the ASC determined from each Appendix 1 shall be the rate applicable to exchange power from that Jurisdiction during the initial Exchange Period. For purposes of this subsection, the initial Exchange Period shall commence on the date the ETCH is terminated; provided that if a Utility Files an initial Appendix I after the twenty-day deadline, BPA may make the new ASC payable only from the date the initial Appendix 1 was actually Filed. However, EPA shall not delay as a result of a late filing of an Appendix 1, the effective date of any change in the ASC if the late filing was the result of unavoidable delay or excusable neglect, and the Utility proceeded to File its initial Appendix 1 as soon as practicable.

2. Thereafter, not later than five (5) working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the Utility shall File a preliminary Appendix 1, setting forth the Costs proposed by the Utility and shall deliver to BPA all information initially provided to the State Commission.

3. Not later than twenty (20) days following the commencement date of a new Exchange Period, the Utility shall File a revised Appendix l, which includes a loss study, reflecting its Costs as approved by the State Commission and a reconciliation of all Costs included on the revised Appendix l 'to the rate order issued by that Utility's State Commission. Subject to the provisions of section III of this rule,- 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 twenty day deadline, BPA may make the new ASC payable only from the date the revised Appendix 1 was actually filed. However, BPA shall not delay as a result of a late filing of an Appendix 1, the effective date of any change in the ASC if the late filing was the result of unavoidable delay or excusable neglect, and the Utility proceeded to File its revised Appendix 1 as soon as practicable.

4. (a) A Utility filing a preliminary Appendix I shall mail written notice thereof to each of BPA's Regional Power Sales Customers or their designee notice of any ASC filing.

   (b) A Utility filing a revised Appendix I -shall mail written notice thereof to each of BPA's Regional Power Sales Customers or their designates notice of any ASC filing. This notice shall make reference to the right to comment thereon and shall state the date the Utility Filed its revised Appendix 1.

C. If BPA or any of its regional power sales customers have been denied the right to participate in a jurisdictional rate review proceeding or 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 BPA has completed its review pursuant to section III of this rule.

III. BPA REVIEW PROCESS:

A. BPA may intervene in each jurisdictional rate proceeding for each Utility participating in the Residential Purchase and Sale Agreement.

B. Each Appendix 1, except those required by section II(B)(2) of this rule, shall be reviewed by BPA or its designee to determine whether the Costs are consistent with generally accepted accounting principles for electric utilities, whether Contract System Costs contains only allowed Costs, and whether the revised Appendix 1 complies with the requirements of this Methodology including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each Appendix 1 shall be reviewed by BPA or its designee to determine whether the Contract System Load used by the Utility is an appropriate load for purposes of the Utility's ASC computation.

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

C. The review period for each Appendix 1 required by section II(B)(I) of this rule shall commence no later than one hundred (100) days from the date the Utility Files the Appendix 1 required by section II(B)(1). BPA shall mail written notice of the date BPA's review period commences to the Utility, to each of BPA's Regional Power Sales Customers or their designee notice of any Appendix 1 filing. The Appendix 1 required by section II(B)(1) o£ this rule shall then be subject to review as set forth in section III(D). For purposes of the review process, the Appendix l referred to in section II(B)(1) shall be deemed to be a "revised Appendix 1" as used in III(D) below and the date the review period commences shall be deemed be the date the Utility Filed its revised Appendix 1.

D. The revised Appendix 1 described in section II(B)(3) of this rule shall be subject to review as follows:

1. Not later than 80 days following the date a Utility Files a revised Appendix 1, only Regional Power Sales Customers or their designee may submit written challenges to Costs included in the Utility's Contract System Costs. The challenge shall identify the specific Cost and state the nature of the challenge. Any of BPA's Regional Power Sales Customers who submit challenges will be accorded automatic party status for purposes of the review process on that Utility's filing. To be considered by BPA, challenges must be received by BPA no later than eighty (80) days following the date a Utility Files its revised Appendix 1. In addition to those of EPA's Regional Power Sales Customers who so request will be accorded party status for a specific filing if said request is received no later than eighty (80) days following the date a Utility Files its revised Appendix 1. For purposes of the review process, the Utility is a party to any review of any Appendix l which is submitted by the Utility.

2. (a) Not later than ninety (90) days following the date the Utility Files its revised Appendix 1, BPA shall mail to the Utility and all parties a notice (1) listing each challenged Cost and the nature of the challenge; (2) listing all parties for the review process for the revised Appendix 1; and (3) requesting comments by all parties on challenged costs.

   (b) Comments shall be submitted in writing to BPA and to all parties. Written comments, to be considered, must be <u>received</u> by BPA and must be mailed to all parties within thirty (30) days of the date of the notice.

   (c) Parties may submit written cross comments in response to the previously submitted comments. Cross comments must be in writing and must be <u>received</u> by BPA and must be mailed to all parties not later than fifteen (15) days following the date the parties submit written comments.

3. Requests for oral argument before the Administrator or his designate must be submitted in writing to BPA with a statement setting forth reasons why the party believes the review process will be enhanced thereby. The written requests for oral arguments must be submitted no later than one hundred and fifty (150) days following the date the Utility Files its revised Appendix 1. BPA may, in its sole discretion, grant the request for oral argument. Requests for oral argument shall be served on all parties.

4. (a) Not later than one hundred and thirty-five (135) days following the date a Utility Files its revised Appendix 1, BPA may, in its sole discretion, issue a notice to all parties requesting comments on Costs that have not been challenged previously, on Contract System Loads, and on other issues that have not been raised previously. Any challenge to the Contract System Load used by the Utility in computing ASC may be raised at this time only, and only by BPA. All comments responding to this notice must be received in writing no later than one hundred and fifty (150) days following the date the Utility Files its revised Appendix 1. In addition to providing the written comments to BPA, any party commenting shall provide all parties with a copy of the comment not later than one hundred and fifty (150) days following the date the Utility Files its revised Appendix 1.

   (b) Parties may submit written cross comments in response to the comments submitted in response to the notice in section III(D)(4)(a) of this rule. Cross comments from all parties must be received in writing by BPA and must be mailed to all other parties not later than one hundred and sixty-five (165) days following the date the Utility Files its revised Appendix 1.

5. In the event a request for oral argument is granted, any party shall be permitted to present oral argument. The presentation of the Utility shall be last. Oral argument shall be presented no later than one hundred and eighty (180) days from the date a Utility Files its revised Appendix 1.

6. The Review Period will and two hundred and ten (210) days from the date the Utility Files its revised Appendix 1. BPA will-issue its final determination not later than two hundred ten (210) days from the date the Utility Files its revised Appendix 1.

   If the date of BPA's final determination or any other deadline contained in these review procedures falls on a Saturday, a Sunday, or a legal public holiday, then the deadline or BPA's final determination shall fall on the first day following that is not a Saturday, a Sunday or a legal public holiday. Legal public holiday means legal public holiday as defined in 5 U.S.C. 6103(a).

E. (1) BPA may request data from the Utility at any time during the Review Period. Each Utility shall respond to reasonable data requests for information relevant to Appendix 1 from BPA, provided that the furnishing of proprietary or confidential information to any party to the review proceedings may be made contingent on the granting of proper safeguards to prevent unauthorized use,or disclosure. The Utility shall provide all the data requested no later than thirty (30) days from the date of BPA's data request. If the Utility objects to the data request, it shall state in writing to BPA the specific basis for its objection no later than twenty-five (25) days from the date of BPA's data request. BPA will issue a ruling as to whether the Utility's objection will be sustained or overruled. If BPA rules that the Utility must comply with the data request, the Utility has fifteen (15) days from the date of BPA's ruling to comply. If the Utility does not provide the data requested, BPA may, in its discretion, remove from Contract System Costs all Costs that are associated with the data not provided.

(2) Data requests from persons or entities other than BPA shall be limited as follows. Each Utility shall respond to reasonable data requests for information relevant to Appendix 1 from any party in the review process for that Utility's Appendix 1, provided that the furnishing of proprietary or confidential information to any party to the review proceedings maybe made contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. A Utility which provides data to any party in response to a data request by that party shall also provide the same data to BPA. Data requests must be received by the Utility no later than forty (40) days from the date the Utility Filed its revised Appendix 1. The data request must identify the specific Cost(s) that is associated with the information requested. The Utility shall provide all the data requested no later than sixty-five (65) days from the date the Utility Filed its revised Appendix 1. If the Utility objects to the data request, it shall state with specificity in writing to BPA the basis for its objection. BPA will issue a ruling as to whether the Utility's objection will be sustained or overruled. The Utility must submit its objection no later than sixty (60) days from the date the Utility Filed its revised Appendix 1. If BPA rules that the Utility must comply with the data request, the Utility has fifteen (15) days from the date of BPA's ruling to comply. If the Utility does not provide the data requested, BPA may, in its discretion, remove from Contract System Costs all Costs that are associated with the data not provided.

(3) All written comments and written cross comments received by BPA by the deadlines set forth above will be included as part of the record supporting the ASC determined by BPA. In addition' all data provided by the Utility as part of its filing in response to data requests from BPA or from any party shall be included as part of the record supporting the ASC determined by BPA. For any jurisdictional rate proceeding in which BPA has intervened, all data received by BPA by virtue of its intervenor status shall also be included as part of the record supporting the ASC determined by BPA.

F. If BPA has not issued a report as of the last date of the review period, the ASC rate shown on the revised Appendix 1 described in section II(B) of this rule Filed by the Utility shall be the ASC from the commencement of the relevant Exchange Period until the date BPA issues its report. The ASC, as determined by BPA, shall then be the ASC rate from the date of BPA's determination until the commencement of the Utility's next Exchange Period.

IV. CHANGE IN AVERAGE SYSTEM COST METHODOLOGY:

The Administrator, at his or her discretion, or upon written request from three-quarters of the Utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of BPA's preference customers, or from three-quarters of EPA's direct-service industrial customers' may initiate a consultation process as provided for in section 5(c) of the Northwest Power Act. After completion of this process, the Administrator may propose a new ASC Methodology to the Commission. However, the Administrator shall not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, *viz*, one year after the then-existing Methodology has been adopted by BPA and implemented by the Commission through interim or final approval, whichever occurs first.

TIMELINE

REVIEW PROCEDURE

BONNEVILLE POWER ADMINISTRATION

DAY	EVENT
-20	COMMENCEMENT OF NEW EXCHANGE PERIOD
0	UTILITY FILES REVISED APPENDIX 1 UTILITY MAILS NOTICE OF FILING.
40	DEADLINE FOR DATA REQUESTS TO UTILITY FROM PARTIES.
60	DEADLINE FOR UTILITY TO OBJECT TO DATA REQUEST FROM PARTIES.
65	DEADLINE TO RESPOND TO DATA REQUEST FROM PARTIES.
80	DEADLINE TO RAISE ISSUES IN THE UTILITY'S ASC FILING (SUBMIT WRITTEN CHALLENGES TO COSTS INCLUDED IN THE UTILITY'S APPENDIX 1).
	DEADLINE TO REQUEST PARTY STATUS FOR ALL PERSONS OR ENTITIES NOT SUBMITTING CHALLENGES TO THE COSTS INCLUDED IN THE UTILITY'S APPENDIX 1.
90	BPA MAILS NOTICE OF ISSUES, LIST OF PARTIES, AND REQUEST FOR COMMENTS.
120	DEADLINE FOR SUBMISSION OF WRITTEN COMMENTS ON FIRST ROUND ISSUES.
135	DEADLINE FOR SUBMITTING WRITTEN CROSS COMMENTS ON FIRST ROUND ISSUES.
	BPA MAILS NOTICE OF SECOND ROUND ISSUES.
150	DEADLINE FOR SUBMISSION OF WRITTEN COMMENTS OF SECOND ROUND ISSUES.
150	DEADLINE FOR REQUESTING ORAL ARGUMENT.
165	DEADLINE FOR SUBMISSION OFWRITTEN CROSS COMMENTS ON SECOND ROUND ISSUES.
180	DEADLINE FOR PRESENTATION OF ORAL ARGUMENT.
210	REVIEW PERIOD ENDS. BPA ISSUES FINAL DETERMINATION.

INSTRUCTIONS

Exhibit C - Appendix 1 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 four 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
Schedule 2 - Weighted Average Cost of Long Term Debt
Schedule 3 - Expenses
Schedule 4 - Average System Cost

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

All references to the Commission accounts are to the Commission Uniform System of Accounts as of July 1, 1984. The Costs includable in the attached schedules are those includable by reason of the definitions in the Commission accounts. If the Commission accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent that RP• determines that a particular change results in a change in the type of Costs allowable for exchange purposes. If the Utility does not follow the Commission accounts, its filing must include a reconciliation between its accounts and the items allowed as Contract System Costs.

BPA may require the Utility to account for purchased 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 State 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 Northwest Power Act.

All schedule entries and supporting data shall be in accord with generally accepted accounting principles and practices as these principles and practices apply to the electric utility industry.

Schedule 1 Exhibit C Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Plant Investment/Rate Base/Rate of Return (Thousands)

			Functionalization		
Line No.	Items	Total To Be Functionalized	Production	Transmission	Other
	(1)	(2)	(3)	(4)	(5)
	PRODUCTION PLANT				
1	Steam Production 310-316				
2	Nuclear Production 320-325				
3	Hydraulic Production 330-336				
4	Other Production Plant 340-346				
5	Total Production Plant				
6	Transmission Plant 350-359 a/				
7	Distribution Plant 360-373 b/				
8	Intangible Plant 301-303 j/				
9	General Plant 389-399 j/				
10	Electric Plant-in-Service				
	LESS:				
11	Depreciation Reserve 108				
12	Steam Plant				
13	Nuclear Plant				
14	Hydraulic Plant				
15	Other Plant				
16	Transmission Plant a/				
17	Distribution Plant b/				
18	General Plant j/				
19	Amortization Reserve 111 j/				
20	Total Depreciation & Amortization				
21	TOTAL NET PLANT				
22	Nuclear Fuel 120.2-120.4 Less 120.5				
23	Accumulated Deferred Debits 186 j/				
24	Cash Working Capital h/				
25	Materials and Supplies 151-157, 163 j/				

	LESS:				
26	Accumulated Deferred Investment				
	Tax Credits/255 j/				
27	Accumulated Deferred Income Taxes/281-283 j/				
28	Other Accumulated Deferred Credits/253, 256-257 j/				
29	Customer Contributions and Aid to Construction/252 j/				
30	Other 106, 124, Various i/ j/				
31	TOTAL RATE BASE				
32	Times Rate of Return @___%, d/				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Weighted Average Cost of Long Term Debt

Line No.	Items	Date of Issue	Date of Maturity	Interest Rate	Iace 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	Weighted Average									
	Cost of Long Term Debt									

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Expenses (Thousands)

			Functionalization		
Line No.	Items	Total To Be Functionalized	Production	Transmission	Other
	(1)	(2)	(3)	(4)	(5)
	PRODUCTION				
1	Fuel 501, 516, 547				
2	Purchased Power 555				
	Operations & Maintenance				
3	Steam 500, 502-514				
4	Nuclear 517,519-532				
5	Hydro 535-545				
6	Other 546,548-554				
7	TOTAL PRODUCTION EXPENSE				
8	TRANSMISSION 560-573 a/				
9	DISTRIBUTION 560-596 b/				
10	CUSTOMER ACCOUNTING 901-905 j/				
11	CUSTOMER ASSISTANCE 907-910 j/				
	ADMINISTRATIVE & GENERAL j/				
	Account Number				
12	920				
13	921				
14	922				
15	923				
16	924				
17	925				
18	926				
19	927				
20	928				
21	929				
22	930				
23	930.2				
24	931				

25	932				
26	Total A & G				
27	TOTAL OPERATIONS & MAINTENANCE				
28	DEPRECIATION & AMORTIZATION 403-407				
29	Steam Production Plant				
30	Nuclear Production Plant				
31	Hydraulic Production Plant				
32	Other Production Plant				
33	Transmission Plant a/				
34	Distribution Plant b/				
35	General Plant j/				
36	Amortization j/				
37	TOTAL DEPRECIATION & AMORTIZATION				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Expenses (Thousands)

			Functionalization		
Line No.	Items	Total To Be Functionalized	Production	Transmission	Other
	(1)	(2)	(3)	(4)	(5)
38	Taxes 408, 409.1 j/				
39	Federal Income Tax j/				
40	State Income Tax				
41	Other Expenses j/				
	Less:				
42	Sales for Resale Rev. 447				
43	Other Operating Revenues 450-456 j/				
44	Billing Credits c/				
45	TOTAL OPERATING EXPENSES				
46	Return from Schedule 1				
47	Other Adjustments				
48	TOTAL COST				

Schedule 3A Exhibit C Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Taxes Other Than Income Taxes (Thousands)

Line No.	Items	Total To Be Functionalized	Functionalization: Production	Transmission	Other
	(1)	(2)	(3)	(4)	(5)
	PRODUCTION				
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				
13a	- Revenue & Business				
14	Idaho - Property				
15	Montana - Property				
16	- Unemployment				
17	Wyoming - Property				
18	- Unemployment				
19	Utah - Property				
20	LOCAL - Occupation and Franchise				
21	IN-LIEU TAXES e/				
22	OTHER				
23	TOTAL				

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

Schedule 3B Exhibit C Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period:
Other Included Items (Thousands)

			Functionalization		
Line No.	Items	Total To Be Functionalized	Production	Transmission	Other
	(1)	(2)	(3)	(4)	(5)
	Operating Revenues:				
1	Sales for Resale 447				
2	1.				
3	2.				
4	Total				
	Other Operating Revenues 450-456 j/				
5	Acct. 450				
6	Acct. 451				
7	Acct. 452				
8	Acct. 453				
9	Acct. 454				
10	Acct. 455				
11	Acct. 456				
12	Total Other Revenues				

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
Test Period:
Average System Cost

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

AVERAGE SYSTEM COST METHODOLOGY

FOOTNOTES

a/ Transmission plant and the associated cost to be used in the calculation of the average system cost (ASC) are limited to:

(1) For transmission plant in service as of July 1, 1984, transmission plant will be as defined by the Federal Energy Regulatory Commission Uniform System of Accounts and will include radial transmission lines.

(2) For transmission plant commencing service after July 1, 1984, transmission plant costs which can be exchanged are limited to transmission that is directly required to integrate resources to the transmission system grid. Specifically, transmission costs which can be exchanged are limited to the lesser of the costs of transmission facilities required to transmit power from the generating resource to the exchanging utility's system or the sum of the costs of the transmission facilities required to integrate the generating resource to the BPA system and the wheeling costs necessary to wheel the power to the exchanging utility's system. If the utility chooses to construct facilities which are more costly than the facilities required to interconnect to the BPA system, the total costs to be exchanged shall be no greater than the facility costs that would have been incurred to interconnect with the BPA system."

b/ 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, point of receipt in the case of purchased power) and of delivery to customers, which are not includable in transmission system, as defined in footnote a(1), whether or not such land' structures, and facilities are operated as part o€ a transmission system or as part of a distribution system. 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 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.

c/ Contract System Costs shall reflect the costs and the revenues arising from conservation and/or retail rate schedules implemented to induce conservation, and for which the utility receives billing credits. These billing credit revenues shall be functionalized on the same basis as the cost of the related conservation measures.

d/ The overall rate of return to be applied to a utility's Exchange Period rate base as shown in Appendix 1 shall be equal to its weighted average cost of long term debt. The utility's overall rate of return times rate base will equal the utility's return provided that if depreciation is not used for jurisdictional ratesetting, then return will be equal to the lesser[**] of: (1) interest expense plus depreciation, or (2) debt service and revenue financed capital expenditures. In no event will the sum of Contract System Cost and Distribution/Other costs be greater than the revenue requirement used to set rates e/ 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 nontax exempt utility to that unit of government. In no event shall the utility's regional total in column 2 be greater than the actual amount paid or the amount used to determine the total revenue requirement for the test period. In-lieu taxes shall be functionalized according to a direct analysis included with the Appendix 1 or to Distribution/Other.

f/ 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 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 BPA's New Resources rates as established from time to time pursuant to section 7(f) of the Regional Act, and as applicable to the utility, and applicable BPA transmission charges if transmission costs are excluded in the determination of BPA's New Resource rate, 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 BPA, pursuant to section 6(c)(1) of the Act; (d) dedicated resources specified in footnote k(1) of this methodology; (e) resources and purchases committed to the utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases shall be priced at the average cost of transmission during the Exchange Period.

(4) Any kilowatthours of New Large Single Loads not met under subsection (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. 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 any energy or capacity interruptive basis, the utility shall prepare a calculation subject to review by BPA 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 that the transmission and generation cost included in the retail rate charged the New Large Single Load.

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

h/ Cash Working Capital greater than 1/8th Operations and Maintenance expenses less fuel and purchased power expenses is functionalized to Distribution/Other. The remainder of Cash Working Capital shall be functionalized on the basis of Operations and Maintenance expenses less fuel and purchased power.

i/ Conservation costs are costs of measures or resources for which power is (or is planned to be) saved by means of physical improvements, alterations, devices, or other installations which are measurable in units. A contract charge paid pursuant to BPA's long term conservation contract will be an allowable conservation cost in Average System Cost. Only conservation costs funded by the utility will be functionalized to Production in the Utility's Average System Cost. Conservation costs incurred to promote changes in consumer behavior including costs attributable to audits, brochures, advertising, pamphlets, leaflets, and similar items, or required by a government entity through building code provisions or programmatic conservation costs in lieu of building code provisions' will be functionalized to Distribution/Other. Conservation surcharges imposed pursuant to section 4(f)(2) of the Northwest Power Act' or other similar surcharges or penalties imposed on a Utility for failure to meet required conservation efforts will also be functionalized to Distribution/Other. Conservation and associated costs must be generally consistent with the Regional Council's resource plan as determined by the Administrator.

j/ FUNCTIONALIZATION:

Except for those accounts that are required to be functionalized under subsection III(C) below, functionalization of each account included in the Utility's ASC shall be by either, but not both, of the following two methods:

(1) direct analysis, or (2) according to the specific functionalization ratios applied to the various Uniform System of Accounts. These two methods are described below in subsections III(A) and III(B), respectively.

I. RULES:

(A) If a Utility has previously functionalized an account by direct analysis as set forth in subsection III(A) below, the utility is not allowed to use the specific functionalization ratio method without prior approval from BPA.

(B) The Utility must submit with its ASC filing any and all workpapers, documents, or other materials that demonstrate that the functionalization under its direct analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation will result in the entire account being functionalized to Distribution/Other.

(C) For Accounts 389, 390, 391 and 392 and Accounts 920, 921, 922, 930.2 and 932, the utility may functionalize these accounts using one, but not any combination, of the following functionalization methods, whichever assigns the highest cost to the Production and Transmission function:

1. Subsection III(A) described below;
2. Subsection III(B) described below; or
3. For publicly-owned and cooperative utilities that have neither generation facilities nor affiliated generation organizations over which the utility exercises over half of the voting rights, 10 percent of gross plant investment may be assigned directly to Production and 10 percent of labor costs assigned to Production. The remainder of Accounts 389, 390, 391, and 392 will be functionalized using Transmission and Distribution Gross Plant Ratios excluding General Plant.

The remainder of Accounts 920, 921, 922, 930.2 and 932 will be functionalized using the Labor Ratio for Transmission and Distribution, and the balance assigned to Distribution/Other.

II. DEFINITIONS:

For purposes of subsections III(A) and III(B) Labor Ratios is defined as the ratios which assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the 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 Federal Energy Regulatory Commission Form 1 (at page 355), or similar document for those utilities not required to file Federal Energy Regulatory Commission Form 1.

III. FUNCTIONALIZATION METHODS:

(A) Be direct analysis which assigns costs to either the production, transmission, or distribution function of the utility. Such analysis is subject to BPA review and approval.

(B) According to the following specific functionalization methods:

ACCOUNT	**FUNCTIONALIZATION METHOD**

I. RATE BASE ACCOUNTS:

310-373 (Plant in Service)	Functionalize directly according to the Federal Energy Regulatory Commission System of Accounts.
389 (Land and Land Rights)	Functionalize on the ratios of Production, Transmission and Distribution Gross Plant excluding General Plant.
390 (Structures and Improvements)	Functionalize on the ratios of Production, Transmission and Distribution Gross Plant excluding General Plant.
391 (Office Furniture and Equipment)	Labor ratios.
392 (Transportation Equipment)	Functionalize on the ratio of Transmission and Distribution Gross Plant excluding General Plant.
393 (Stores Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
394 (Tools, Shop and Garage Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
395 (Laboratory Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
396 (Power Operated Equipment)	Functionalize on the ratio of Transmission and Distribution Gross Plant excluding General Plant.
397 (Communication Equipment)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
398 (Miscellaneous Equipment)	Functionalize** to Distribution/Other.
399 (Other Tangible Property)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
301-303 (Intangible Plant)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
114 (Acquisition Adjustment)	Labor Ratios.
105 (Plant Held for Future Use)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant including General Plant.
120.2-120.4 less 120.5 (Nuclear	Functionalize to Production.

Fuel)	
186 (Miscellaneous Debits)	Labor Ratios.
252 (Customer Advances)	Functionalize to Distribution/Other
253 (Other Deferred Credits)	Functionalize to Distribution/Other
255 (Accumulated Deferred Investment Tax Credits)	Functionalize to Distribution/Other
257 (Unamortized Gain Reacquired Debt)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant including on General Plant.
281-283 (Accumulated Deferred Income Taxes)	Functionalize to Distribution/Other
151-152 (Fuel Stock)	Functionalize to Production.
153-157, 163 (Materials and Supplies)	Functionalize on the ratio of Transmission and Distribution Gross Plant including General Plant.
106 (Completed Construction not Classified)	Functionalize on the ratio of Production, Transmission and Distribution Gross Plant excluding General Plant.
124 (Other Investment)	Functionalize to Distribution/Other.
184 (Clearing Accounts)	Labor Ratios
Other Rate Base Accounts	Functionalize to Distribution/Other.

2. EXPENSE ACCOUNTS:

501-577 (Fuel, Purchased Power and Power Production Expenses)	Functionalize to Production.
560-573	Functionalize to Transmission.

(Transmission Expenses)	
580-598 (Distribution Expenses)	Functionalize to Distribution/Other.
901-905 (Customer Accounts Expenses)	Functionalize to Distribution/Other.
907 (Customer Service Information Expenses-Supervision)	Functionalize to Distribution/Other.
908-910 (Other Customer Service Information Expenses)	Functionalize to Distribution/Other.
911-916 (Sales Expenses)	Functionalize to Distribution/Other.
920 (Administrative & General Salaries)	Labor Ratios.
921 (Office Supplies & Expenses)	Labor Ratios.
922 (Administrative Expenses Transferred-Cr.)	Labor Ratios.
923 (Outside Services Employed)	Labor Ratios.
924 (Property Insurance)	Functionalize on the ratio of Production, Transmission, and Distribution Gross Plant including General Plant.
925 (Injuries & Damages)	Labor Ratios.
926 (Employee Pensions & Benefits)	Labor Ratios.
927 (Franchise Requirements)	Functionalize to Distribution%Other.

928 (Regulatory Comm. Fees & Expenses)	Functionalize to Distribution/Other
929 (Duplicate Charges-Cr.)	Labor Ratios.
930.1 (General Advertising)	Functionalize to Distribution/Other.
930.2 (Miscellaneous General Expenses)	Functionalize to Distribution/Other.
931 (Rents)	Functionalize to Distribution/Other.

3. REVENUE ACCOUNTS:

447 (Sales For Resale)	Functionalize to Production.
450-455 (Other Operating Revenues)	Functionalize to Production.
456 (Wheeling Revenues)	Functionalize to Transmission.

(C) THE FOLLOWING ACCOUNTS SHALL BE FUNCTIONALIZED AS FOLLOWS:

107, 120.1 (CWIP)	Functionalize to Distribution/Other.
108 (PIS Depreciation Reserve)	The same functionalization used for accounts 310-373, Plant in Service (PIS).
108 (General Plant Depreciation Reserve)	Functionalize according to the General Plant ratio.
111 (Accumulated Amortization)	The same functionalization used for accounts 301-303, Intangible Plant.
256 (Deferred Gain from Disposition of Utility Plant)	The same functionalization used for account 105, Electric Plant Held for Future Use.
403-407 (PIS Depreciation Expense)	The same functionalization used for Accounts 310-373, Plant in Service.

408.1 (Other Taxes)	With the exception of property taxes and labor related taxes, all taxes will be functionalized to Distribution/Other. Property taxes will be functionalized using the gross plant ratio including general plant. Labor related taxes will be functionalized using labor ratios.
409.1, 410.1, 411.1, 411.4 (Income Taxes)	Functionalize to Distribution/Other.
932 (Maintenance of General Plant)	Functionalize according to the ratio developed from the functionalized totals of accounts 390, 391, 397 and 398.
411.6, 411.7 (Gain from Disposition of Utility Plant)	The same functionalization used for Account 105, Plant Held for Future Use.