1983 FINAL RATE PROPOSAL

ADMINISTRATOR'S RECORD OF DECISION

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BPA

BONNEVILLE POWER ADMINISTRATION
U. S. DEPARTMENT OF ENERGY

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September 1983

1983 WHOLESALE POWER AND TRANSMISSION RATE PROPOSAL

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CHAPTER I

INTRODUCTION

A. Procedural History of the Rate Proceeding

On January 28, 1983, BPA published notices of intent to revise its wholesale power and transmission rates, 47 FEDERAL REGISTER 4027 and 4028. BPA's initial proposals for revised rates were issued on March 28, 1983, 47 FEDERAL REGISTER 12,766 and 12,777. The proposed increases approximated 27 percent in the average rate to be charged power customers and 36 percent in the average rate for the transmission of non-Federal power. The proposed effective date for these rate increases is November 1, 1983, subject to the interim approval of the Federal Energy Regulatory Commission.

In accordance with section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (the Regional Act), 16 U.S.C. §839e(i), an evidentiary hearing on the proposed rate adjustments was conducted by Judge Seymour Wenner, Hearing Officer. Forty-six interventions were filed by publicly owned and investor-owned utility customers, direct service industrial customers, federal and state agencies, public interest groups and Congressman James Weaver. Judge Wenner commenced the proceedings with two prehearing conferences at which rules of practice and procedural schedules were discussed by the parties. Thereafter, the judge issued special rules of practice on April 11, 1983.

BPA's initial proposal consisted of the written testimony, schedules and exhibits of 31 witnesses. BPA responded to 1,100 data requests concerning all aspects of its initial proposal. Supplemental testimony to update BPA's revenue forecast was filed on June 1, 1983. Eighteen days of clarifying sessions, transcribed oral discovery, were conducted between April 25 and June 8, 1983. Judge Wenner was asked to resolve several disputes regarding the scope of discovery.

On May 23, 1983, the parties filed extensive testimony and exhibits. This was followed by a separate round of written discovery and clarifying sessions.

Cross-examination began on June 8, 1983, and extended through June 30, 1983. During the hearing Judge Wenner ruled on motions to strike numerous passages of prepared testimony. He granted all motions relating to testimony that was irrelevant, unsubstantiated or based on legal conclusions.

BPA and the parties simultaneously filed rebuttal testimony on July 8, 1983. Further cross-examination occurred from July 18 to July 22, 1983. BPA filed supplemental testimony on July 26, 1983, to correct a technical error in its revenue requirement calculation. An additional clarifying session was conducted on July 27 and BPA's sponsoring witnesses were cross-examined by deposition on July 29, 1983.

Oral argument occurred on August 1, 1983, before a panel comprised of Peter Johnson, Administrator, Robert Ratcliffe, Deputy Administrator, and Edward Sienkiewicz, Assistant Administrator for Power Management.

Initial briefs were filed by nearly all parties on August 5, 1983; however, the filing deadline for initial briefs was August 15, 1983.

For interested persons who did not wish to become parties in the formal evidentiary hearings, BPA conducted a series of eight field hearings during April in Portland and Eugene, Oregon; Tacoma, Lynnwood, Spokane and Richland, Washington; Burley, Idaho; and Missoula, Montana. A second set of field hearings was conducted during July. BPA has also received 213 written comments, plus 2,091 letters and 21 telephone calls. Transcripts of the field hearings, the written comments and letters, and notes on oral communications become part of the record on which the Administrator bases his decisions.

On August 18, 1983, BPA issued its Evaluation of the Record. This document was intended to present the BPA Administrator's decisions on each of the issues raised in the 1983 rate proceedings, based on his review of the evidence, the oral arguments and the initial briefs. However, these tenative decisions were not final in either the legal or the practical sense. The Administrator has reconsidered his decisions based on the parties' reply briefs, filed on September 2, 1983.

This Record of Decision is divided into the following two sections: (1) comments by the parties which were generally of a specific and technical nature; and (2) comments of the participants which were of a more general nature. The parties' comments are evaluated in six chapters corresponding with the rate adjustment process: Preliminary Issues concerning the determination of BPA's loads and resources; the Revenue Requirement Study to determine BPA's revenue requirements; the Time-Differentiated Long Run Incremental Cost Analysis to evaluate the cost variation faced by BPA in meeting load growth; the Cost of Service Analysis to identify the average costs associated with providing BPA's services; the Wholesale Power Rate Design Study and the Transmission Rate Design Study. These last two chapters dealing with the parties' comments describe the ratemaking process and other integral studies used in revision of the specific rate structures. BPA prepared a Draft Environmental Impact Statement (DEIS) on the initial Wholesale Power rate proposal and a Draft Environmental Assessment (DEA) on the initial Transmission rate proposal. Comments on the DEIS and DEA will be addressed in the next two chapters of this Record of Decision. Consistent with the Council on Environmental Quality guidelines for preparation of environmental documents, the comments received on the DEIS also have been addressed in the Final EIS.

Within the individual chapters addressing the comments of the parties specific issues are identified. The evaluation of each is divided into three sections: (1) summary of the positions which briefly states the BPA proposal and the positions the parties have taken on the record concerning the issue; (2) evaluation of the positions which discusses the various arguments on the issue and presents BPA's evaluation of the arguments; and (3) the decision which is the Administrator's decision on the issue. The chapter addressing the comments of the participants has a similar structure. The participants comments have been aggregated into 17 general topics. Within each topic, individual issues have been identified that reflect the concerns expressed by the public. Where the issues identified by the participants overlap those raised by the parties, a general evaluation is provided and reference is made to the more technical evaluation contained in the earlier portion of the document.

Two additional matters must be addressed to complete the discussion of the procedures utilized in this case.

First, the briefing schedule in this proceeding and the development of tentative decisions in the Evaluation of the Record were not expressly contemplated by section 1010.3 of the Procedures Governing Bonneville Power Administration Rate Adjustments, 47 FEDERAL REGISTER 6240 (February 10, 1982). However, each of these procedural innovations were developed at the request of the parties for additional participation in the ratemaking process. To the extent that any technical inconsistency exists between section 1010.3 and the procedures adopted in this case, good cause exists for waiving any conflicting requirements of section 1010.3.

Second, this Record of Decision is the product of the Administrator's deliberations on the issues raised in this ratemaking proceeding. Staff participation in an undertaking of this magnitude is obviously necessary and BPA is not constrained by rules that separate the functions of agency personnel in adjudicatory proceedings. However, decisionmaking is the function of the Administrator and he has satisfied that obligation in this proceeding.

B. Legal Requirements

1. General Rate Guidelines

Section 6 of the Bonneville Project Act, 16 U.S.C. §832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers to be effective upon confirmation and approval by the Federal Energy Regulatory Commission (FERC). This section allows the Administrator to modify BPA rate schedules from time to time and directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the Bonneville Project Act, 16 U.S.C. §832f, provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the capital investment over a reasonable period of years.

The Federal Columbia River Transmission System Act (Transmission Act), 16 U.S.C. §838, provides requirements parallel to those of the Bonneville Project Act. The Transmission Act provides three specific guidelines for the establishment of rates by the Administrator: (1) encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) set rates with regard to the recovery of the cost of producing and transmitting electric power, including the amortization of the capital investment allocated to power over a reasonable period of years; and (3) set rates at levels which produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission Act, including amounts required to establish and maintain reserve accounts.

The Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), 16 U.S.C. §839e, provides additional rate guidelines. The Regional Act directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. The rates are to be set so that BPA recovers, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and any other costs incurred by BPA pursuant to the Regional Act or other laws.

The Regional Act specifies in section 7(a)(2) that rates become effective upon final or interim approval of the FERC. FERC must review the rate proposal to determine that (1) rates are sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; (2) rates are based on BPA's total system costs; and (3) transmission rates equitably allocate costs of the Federal transmission system between Federal and non-Federal power using the system. FERC issued an order resolving the scope of its jurisdiction at 20 FERC 61,292 (1982).

Both the Bonneville Project Act and the Transmission Act recognize that many hydroelectric projects serve multipurpose functions, including navigation, flood control, and irrigation, in addition to the generation of electric power. Section 7 of the Bonneville Project Act allows FERC to allocate to the costs of electric facilities such a share of the costs of facilities having joint power and nonpower uses as the power development may fairly bear as compared with such other purposes. Section 11(b)(9) of the Transmission Act enables the Administrator to make such payments for reclamation projects that are required by law.

2. <u>Repayment Criteria</u>

BPA conducts a repayment study in accordance with law in order to determine if current rates are sufficient to repay the Federal capital investment over a reasonable number of years. Several sources dictate the requirements of this repayment study. Section 2 of Pub. L. No. 89-448, 80 Stat. 200, requires the Secretary of Interior to take prompt action to adjust rates if it appears that costs of Federal projects will not be returned under current rates within the period prescribed by law. A BPA General Counsel's opinion, dated February 6, 1979, provides for the exclusion from the

Repayment Study of those Federal power projects authorized by Congress, but not yet in service.

In addition to these requirements, statutory limitations have been placed on the extent to which power revenues may subsidize reclamation projects. Section 6 of Pub. L. No. 89-561, 80 Stat. 707, limits BPA payments for reclamation projects to be made only from the net revenues of the FCRPS and provides that the total assistance to all irrigation projects in the Pacific Northwest shall not average more than $30,000,000 annually.

Under Department of Energy Order No. RA 6120.2, the repayment of annual interest expense may be deferred temporarily in unusual circumstances. The amount of interest deferred, however, must be capitalized and amortized with a high rate of interest, and all deferrals must be repaid before funds can be applied to the amortization of the Federal investment.

3. Equitable Recovery of Transmission Costs

Both the Transmission Act and the Regional Act (as noted above) require the equitable allocation of the costs of the Federal transmission system between Federal and non-Federal power using the system. The Transmission Act, in section 10, provides that schedules for transmission rates and charges may provide for uniform rates or rates uniform throughout prescribed transmission areas. The costs associated with that portion of the transmission system used for the transmission of Federal power to BPA's customers must be recovered from power rates.

4. Equitable Sharing of Benefits by Regions

In addition to the general rate guidelines and those relating to transmission, BPA is charged with certain marketing restrictions relating to sales outside the Pacific Northwest by the Pacific Northwest Regional Preference Act (Pub. L. No. 88-552; August 31, 1964; 78 Stat. 756). Section 5 of the Act, although discussing permissible exchanges of energy between the Pacific Northwest and other regions, requires that the benefits of such exchanges must be shared equitably by the areas involved.

That statutory charge, combined with the language from section 6 of the Bonneville Project Act and section 10 of the Transmission System Act allowing for "uniform rates or rates uniform throughout prescribed transmission areas," and the appropriate rate forms noted in section 7(e) of the Regional Act, indicates a Congressional acceptance of rates designed for power sales within the Pacific Northwest and rates for power sales outside that region. Indeed, section 7(k) of the Regional Act acknowledges that the Administrator may establish rates for the sale of electric power within the United States, but outside the region. However, it should be noted that the final proposed rates would apply uniformly inside and outside the Pacific Northwest. There is no separate schedule of rates for sales outside the region.

Furthermore, the Senate and House Committee Reports on Pub. L. No. 88-552 and the Congressional Record remarks of individual Senators and Congressmen clearly indicate that in enacting the Regional Preference Act it was contemplated that there should be a continuing and mutual sharing of benefits between the Pacific Northwest and the Pacific Southwest in all power sales, not just exchanges of energy or capacity under section 5 of the Regional Preference Act. Of course, a sharing of benefits necessarily connotes a mutual sharing of the costs of the Federal Columbia River Power System.

5. Regional Act Rate Pools

In addition to providing general revenue requirement guidelines, the Regional Act also establishes three rate pools. Section 7(b)(1) of the Regional Act establishes requirements for public body, cooperative, Federal agency and residential exchange loads (section 5(c) of the Regional Act) for the period prior to July, 1985. Rates for direct-service industrial customers are established, for the period prior to July 1985, under section 7(c). Finally, rates for all other firm power sales under the Regional Act are established pursuant to section 7(f).

6. Confirmation and Approval

Pursuant to section 7(i)(6) of the Regional Act, as noted above, the final decision of the Administrator becomes effective upon interim or final approval of the proposed rates by the Federal Energy Regulatory Commission (FERC). Pursuant to section 7(i)(6) of the Regional Act, the FERC, by order dated December 4, 1981, promulgated rules establishing procedures for the interim approval of BPA rates. (46 F.R. 60813). These rules were promulgated on an interim basis and are subject to FERC notice and comment procedures before being finalized, and to date have not been finalized.

CHAPTER II

PRELIMINARY ISSUES

A. Introduction

The first preliminary issue, the Loads and Resources Study, is the initial step in the rate development process. The results of this study are incorporated into the Revenue Forecast Study, the Cost of Service Analysis (COSA), and Wholesale Power Rate Design Study (WPRDS).

The determination of loads and resources is a dynamic process that is based on assumptions that underlie forecasts of loads, conservation program estimates, available resources, and policy determinations for resource acquisitions. The load forecast represents BPA's estimate of the expected total loads of its major customer groups: non- and small generating public utilities, generating public utilities, direct service industries (DSI's), private utilities, Federal agencies, and United States Bureau of Reclamation (USBR).

BPA projects the level of residential exchange loads/resources expected to be placed on BPA during the rate period, and from this the cost of exchange resources that BPA will expect to acquire. This information is a part of the determination of BPA's rate period costs.

The forecast of conservation program estimates incorporated into the load forecast quantifies the capacity and energy savings from programmatic conservation expenditures categorized by program and major customer group.

The forecast of available resources includes the projected operating cycles of the region's thermal resources, as well as the projected output of hydro facilities. Resources are adjusted by the projected unidentified resource acquisitions to be acquired under the direction of the Regional Act. The load and resource projections together, along with assumptions regarding shaping resources over the 4-year critical period, determine the surplus or deficit of resources expected over the rate period for both capacity and energy. From these determinations BPA must derive an estimate of the amount of firm surplus power, as well as determine how much of this surplus can be successfully marketed as firm power or energy under the proposed rates and how much is available for capacity sales.

Another preliminary issue is the Revenue Forecast Study in which BPA conducts a pre-rate period revenue forecast in order to assess BPA's financial position at the beginning of the rate period.

The final preliminary issue is the classification of costs between demand and energy. Questions of classification pervade the rate development process from the load forecast to rate design. For this reason, classification is addressed as a preliminary issue.

B. Loads and Resources Study

The estimate of the amount of firm surplus power available for sale in the test year is a derived number, dependent on load and resource estimates. Inasmuch as issues discussed in the following section relate to changes in estimated loads or resources they impact the estimated surplus.

The marketability of the estimated surplus is an important matter in considering loads and resources. Any firm surplus estimated to be available to sell in the test year, but not likely to be marketable at rates that recover fully allocated costs, results in a requirement for additional BPA revenue from other resource sales. This issue has been particularly important to BPA recently, as attempts to market all available firm surplus have not been successful.

The following discussion first presents issues related to loads. Next, issues related to resources are reviewed. Finally, the question of marketability of firm surplus is addressed.

1. Load Forecasts

For the 1983 rate proposal some new methodologies were used to forecast the loads of BPA's major customer groups. Each forecast will be briefly discussed below and then will be expanded upon when specific issues are considered. The non- and small generating public utility load forecast was based on econometric methods. The DSI forecast is based on a model that simulates the economics of aluminum company potline operations. The generating public utility load forecast is based on individual utility's 1983 submittals to the Pacific Northwest Utilities Conference Committee (PNUCC). The forecast of investor-owned utilities' total loads is based on the BPA 1982 Long-Term Regional Forecast. Individual 1982 private utility forecasts are the basis of the IOU residential exchange forecast. The forecast of Federal agency loads was developed by BPA area offices in cooperation with each agency. Finally, the USBR "reserved energy" load forecast was provided by the USBR.

Forecasts of all customer groups, with the exception of the DSI forecast, remained the same from the initial to the final rate proposal. The updated DSI forecast is based on a more complete computer model and inputs that were publicly available. Estimates of Federal transmission losses also were revised. These revised losses are based on a BPA study of losses that became available after the initial proposal was completed.

a. Direct Service Industrial Loads

Until recently, BPA forecasts of DSI loads have been based solely on contract demands contained in each industrial customer's power sales contract with BPA. These contracts were used as the justification for including maximum contract amounts in previous forecasts of DSI loads, even though the DSI's (collectively and individually) have not always utilized their total contract demands.

Under the Regional Act, new power sales contracts were executed with the DSI's that include provisions for both contract and operating demands. For the 1982 wholesale power rates, BPA based its DSI load forecast primarily on projected operating demands supplied by the DSI's themselves. Subsequent depressed economic conditions led to curtailed levels of production and load below that expected in the forecast. DSI loads during OY 1982-83 were well below prevailing operating demands. These operating demands, used as the basis for a DSI load forecast and subsequent decisions regarding ratesetting, exposed BPA to significant underrecovery of revenues. As a result of these circumstances, BPA determined that it was appropriate to base the DSI forecast for the 1983 rates on operating levels that represent the best estimates of projected near-term DSI loads. Hoffard, BPA, E-BPA-3, 30-33.

The logic, methodology, and inputs to the DSI load forecasting process were developed during late 1982 and early 1983 by BPA with the assistance of concerned regional groups, DSI representatives, and industry analysts. The resulting forecast was presented in BPA's initial testimony. Hoffard, BPA, E-BPA-11, 5-11.

A supplemental forecast was developed during the course of the rate proceeding. Hoffard & Moorman, BPA, E-BPA-11S. The supplemental forecast relied on publicly available data. While it retained the basic methodology of the earlier forecast, the supplemental forecast was based on a computer simulation model developed through informal technical sessions. These technical sessions were open to all parties and conducted in cooperation with representatives of the Northwest utilities and other parties. The supplemental forecast incorporated updated data on the price of aluminum, power rates, and other production costs.

(1) Forecast Uncertainty

Issue #1

Should the DSI forecast reflect uncertainties about the predictive ability of the DSI load model?

Summary of Positions

BPA's forecast of DSI loads proceeded through several stages. The initial forecast was based on a single load scenario that did not reflect economic uncertainty. BPA, E-BPA-3, 30-37; Hoffard, BPA, E-BPA-11, 5-11. BPA later introduced a different DSI forecast in supplemental testimony based on two load scenarios that reflected assumptions accommodating uncertain conditions in the aluminum industry. The two scenarios provided a range of possible DSI load projections for use in deriving an appropriate forecast for rate purposes. Moorman, BPA, TR 3954-3955.

The scenarios reflect optimistic and pessimistic forecast assumptions. The optimistic scenario represented a projection of DSI loads at full capacity utilization of aluminum plants. There is virtually no possibility of loads being higher than the optimistic scenario. The pessimistic scenario reflected uncertain conditions in the aluminum industry by using a lower projected price of aluminum over the forecast period, the most significant input into the forecast. Hoffard & Moorman, BPA, E-BPA-11S, 9-12. The DSI forecast adopted by BPA in supplemental testimony was the result of an average of the optimistic and pessimistic scenarios. BPA found no reason to weigh one of the scenarios more highly than the other. Pollock, BPA, TR 3996.

The Northwest Utilities (NWU's) proposed an alternative DSI load forecast. This forecast used a model similar to BPA's, but was based on one scenario. Allcock, NWU, E-NW-3, 1-15. The use of one scenario follows BPA's initial forecast approach. The NWU's acknowledged that there is uncertainty in the DSI forecast, but the NWU's did not accept BPA's averaging of the optimistic and pessimistic scenarios. McCullough & Wolverton, NWU, E-NW-24R, 11-19; Opening Brief, NWU, B-NW-01, 25-26.

The DSI's did not introduce any evidence on forecasting their own loads, even though they are in the best position to do so. The DSI's agree with BPA, that there is a fair amount of uncertainty in predicting the price of aluminum, the major variable in the DSI forecast. Opening Brief, DSI, B-DS-01, 113; Peseau & Kavanaugh, DSI, DS-18-R, 2-5; and Peseau & Kavanaugh, DSI, DS-22-SR, 2,7.

Evaluation of Positions

BPA acknowledged NWU's concern over BPA's initial forecast and provided an alternative forecast based on two scenarios in supplemental testimony. Hoffard & Moorman, BPA, E-BPA-115; Pollock, BPA, E-BPA-155, 2-3. The NWU's recognized that this concern was eliminated by BPA's supplemental testimony. McCullough, NWU, TR 7388-7389. In fact, the BPA and the NWU models used to forecast DSI loads are almost identical. McCullough, NWU, TR 7389. BPA, however, does not agree that the DSI forecast should be based on a single load scenario that does not incorporate uncertainty, as the NWU's propose.

Several of the DSI's could curtail or cease operations in the Northwest for factors not explicitly represented in BPA's model. Pollock, BPA, E-BPA-155, 3. There is also considerable uncertainty associated with the aluminum price forecasts used in both the BPA and the NWU models. Moorman, BPA, TR 3954-3955. The ramifications of these uncertainties, if actual loads deviate significantly below forecast loads, is demonstrated by the FY 1982-1983 revenue shortfall. BPA, E-BPA-7, 28.

Decision

It was BPA's intention to reflect uncertainty in its DSI forecast through averaging an optimistic and pessimistic DSI load scenario. BPA acknowledges that averaging the two scenarios may not have analytic elegance. However, the use of a weighted average is a reasonable way of reflecting the inherent uncertainty of forecasting. Pollock, BPA, TR 3996; Pollock, BPA, E-BPA-155, 2-3. BPA cannot risk its revenues on a full capacity load forecast.

In consideration of evidence presented by the NWU's during the hearings and recent events in the aluminum industry, BPA has decided to change its weighting of the two load scenarios. The recent recovery in aluminum markets has pushed the price of aluminum above that used in the optimistic scenario. Opening Brief, NWU, B-NW-01, 25. Reynolds Aluminum and Arco have applied for additional energy under BPA's offer of nonfirm power. The fact that this has occurred when the offer is about to expire, suggests that these companies have more optimistic expectations for the future. These factors suggest that it is appropriate to place more weight on the optimistic scenario.

With these facts in mind, BPA has changed the relative weights of the pessimistic and optimistic scenarios to 15 percent and 85 percent, respectively. This weighting reflects BPA's belief that there still exists uncertainty about future DSI loads remaining at full capacity throughout the forecast period. It also reflects NWU's position that BPA's optimistic scenario, "is close to the mark." Opening Brief, NWU, B-NW-01, 25-26. BPA notes that the NWU's made a valuable contribution to forecasting DSI loads through the cooperative process that emerged from early disputes over proprietary data inputs in BPA's initial forecast.

(2) Costs of Production

Issue #1

Were BPA's aluminum smelting production costs reliable?

Summary of Positions

NWU's brought up several issues concerning the assumed aluminum smelting production costs used in the DSI forecast. Almost all of NWU's cost estimates were lower than BPA's. This resulted in a lower overall marginal production cost and, therefore, a more optimistic level of load. That is, NWU's DSI load forecast reached full production capacity sooner, at all prices of aluminum, than did BPA's. Allcock, NWU, E-NW-03; Moorman, BPA, TR 3827-3828; Moorman TR 3853-3854; Moorman, BPA, TR 3861.

The NWU's argued that BPA's energy efficiency estimates, labor costs, alumina costs, and transportation costs were not reliable. They argued that BPA should use their estimates. Baxendale, NWU, TR 3806-3862.

Evaluation of Positions

All of BPA's production cost estimates were based on reliable, publicly available data. BPA based its estimate of energy efficiencies on an average of five sources. Hofford & Moorman, BPA, E-BPA-11S, 4-5. BPA's estimates of labor costs were taken from Paine Webber aluminum production cost data. Hoffard & Moorman, BPA, E-BPA-11S, 7. This estimate included an estimate of supplemental unemployment benefits (SUB), and was not on an individual plant basis. The alumina cost estimates were based on data from Paine Webber aluminum production cost data and verified with data from the Bureau of Mines. Hoffard & Moorman, BPA, E-BPA-11S, 6. BPA did not include a fixed cost of alumina component in its cost estimate because the data does not support fixed costs as a factor in aluminum plant operating decisions.

BPA's efficiency estimates of kilowatthours per pound used in the DSI forecast were derived from several sources. Hoffard & Moorman, BPA, E-BPA-11S, 4-5. In contrast with BPA's estimates, NWU's were based on a single simple linear regression equation which gave some questionable results. Lyman, et al., NWU, E-NW-4, 3-6.

BPA recognizes that individual labor cost information might be desirable in a DSI forecast. BPA did not use plant-by-plant data for two reasons: first, BPA did not have reliable plant-by-plant data at the time the DSI load forecast was completed, Moorman, BPA, TR 3825; and second, NWU's plant by plant data was of questionable quality. This is evidenced by the statement that, "it is not obvious how eager a firm will be to lay off a worker whose unemployment benefits must be paid." Lyman, et al., NWU, E-NW-4, 10.

The NWU's argued that a DSI forecast should employ estimates of alumina fixed costs. Lyman, et al., E-NW-04,12. BPA does not have any evidence that suggests that when production decisions are made, company management actually consider fixed alumina costs. Moorman, BPA, TR 3834-3835. Even though the NWU's use fixed costs, they indicated that their fixed costs assumptions were uncertain. McCullough, NWU, TR 7382-7383.

The NWU's tried to downplay the effect of the Pacific Northwest's locational disadvantage relative to major markets. Moorman, BPA, TR 3839-3847. During this line of questioning, the NWU's provided documentation (E-NW-14, Foreign Import and Export Statistics) which purported to demonstrate that Japan was a major market for PNW aluminum production. Consequently, the NWU's wanted BPA to conclude that the PNW would not have the locational disadvantage to major markets that BPA had assumed. The result of this reasoning would lower the estimate of transportation costs. However, in redirect it was established that the exports to Japan identified in this document could not be determined to be from the PNW aluminum plants, but could have come from any plants in North America. Moorman, BPA, TR 3960-3963.

Decision

BPA's production cost estimates were based on reliable, publicly available sources of data. While the NWU's provided numerous valuable comments, BPA believes that the NWU's estimates are suspect and need further study. Therefore, BPA has decided that it's production cost estimates should not be changed.

2. Resources

BPA has determined that for the rate period BPA will have resources in excess of firm loads. BPA must determine its projected firm power obligations in the test period. BPA must also determine the amount of firm power resources it is prudent to assume will be available in the test period. Issues involved in determining the firm resource calculations include: (1) levelizing hydro generation versus levelizing the surplus over the critical period; (2) use of a 39-month average versus a 42-month average to determine hydro capability over the critical period; (3) the appropriate assumptions concerning the output of Hanford and Washington Public Power Supply System WNP-2 in the test period; and (4) whether BPA should assume that exchange purchases will be displaced.

BPA finds that based on the most probable projection of firm power loads and planned firm power resource operations, BPA has electric power in the test period that is surplus to its sections 5(b), 5(c), and 5(d) obligations under the Regional Act. BPA's initial proposal estimated that 828 average megawatts of firm surplus power would be available in operating year (OY) 1985 for all months except May. BPA, E-BPA-3, 65. In supplemental testimony, BPA increased the estimate of firm surplus in OY 1985 to 1030 average megawatts for all months except May. Pollock, BPA, E-BPA-15S, 3. The quantity of estimated firm surplus is derived after determining the most probable level of projected firm loads and planned firm power resource operations in the test period.

Other issues relating to firm resource calculations and firm resource sales include: (1) determining the amount of surplus firm power that BPA will be able to market in the rate period; and (2) determining if BPA has marketable excess capacity available from its resources during the test year.

a. Operation of WNP-2 and Hanford NPR reactor

Issue #1

Given the current Federal firm power surplus during the rate period, what should BPA assume for rate study purposes with regard to operation of WNP-2 and Hanford NPR reactor?

Summary of Positions

BPA has included Hanford and WNP-2 as operating resources in studies for the 1983 rate proposal. Fifty percent of the planned output of Hanford, or 212 average megawatts, is included for the two 42-month critical periods starting September 1, 1983, and September 1, 1984. WNP-2 has a planned generation of 622 and 723 average megawatts included for the two critical periods, respectively. BPA, E-BPA-3, 66.

The DSI's discuss the reasons why WNP-2 and Hanford should not be operated during a surplus period. Mizer, DSI, E-DS-13, 24-30. Their argument is summarized as follows: "to plan the unnecessary operation of Hanford or WPPSS 2 during a period of surplus firm power is harmful, not helpful, to all BPA customers <u>if</u> BPA insists on assuming that it cannot sell its surplus power at full cost." Mizer, DSI, E-DS-13, 30.

<u>Evaluation of Positions</u>

BPA supplemental testimony indicated that for OY 1985 the firm surplus would be about 1030 megawatts. WNP-2 and Hanford represent 935 megawatts of planned energy. BPA, E-BPA-3, 65-66. If these are assumed to be the resources which represent the surplus, and 700 megawatts of the total are sold at the surplus firm power rate (31.7 mills/kWh) and the remainder at the nonfirm rate average (14.6 mills/kWh), Metcalf, BPA, E-BPA-32S, Attachment 1, 8, then the weighted average revenue from that combination of sales (26 mills/kWh) is greater than either the cost of operating WNP-2 (7 mills/kWh) or Hanford (19 mills/kWh). Even after considering that some energy from the facilities might be sold at nonfirm rates, BPA's total revenues are clearly enhanced.

BPA testified that under such circumstances it would be prudent to plan to operate the resources. Pollock, BPA, TR 4389. Even if the firm surplus is not marketed or nonfirm energy cannot be sold at a rate high enough to cover the operating costs of WNP-2, BPA has the option during the rate period of operating WNP-2 only if that operation is expected to produce more revenues than the cost to operate. Because BPA's floor nonfirm rate is higher than the cost to operate WNP-2 (7 mills/kWh), only in the case of a spill condition would BPA risk a net revenue loss from operation of the plant. Under average water conditions, spill conditions occur primarily in the spring when these plants are on maintenance schedules.

For Hanford operation, BPA would pay an estimated maximum cost of 19 mills/kWh regardless of whether the plant operates, because there is no incremental cost associated with the Hanford agreement. The agreement between BPA and the Supply System allows BPA to terminate the operation of Hanford with a 1-year notice. Contract Nos. DE-AC06-82RL10379; DE-MS79-82BP90944. Hanford operation cannot be terminated without the mutual consent of the Supply System, BPA and the investor-owned utilities with an interest in the project output. Contract Nos. DE-AC06-82RL10379, 3; DE-MS79-82BP90944, 3; DE-MS79-83BP90951. In addition, once terminated, BPA cannot restart the plant. <u>Id</u>. Therefore, if BPA were to terminate operation, the project would be lost for the remaining life of the contract, extending to 1993. Mizer, DSI, E-DS-13, 27-29. During this period, BPA faces a declining surplus which becomes a gradually increasing deficit. While in the test year the power from Hanford is arguably of a value consistent with incremental revenues from surplus sales, in later years it must be valued in excess of the New Resources rate which represents the current cost of purchasing new resources. (29.7 mills/kWh). Given these circumstances, it would be imprudent to forego a 19 mill cost resource in the late 1980's and 1990's.

The DSI's have no analysis to conclude that the operation of WNP-2 and Hanford is a detriment to BPA customers. The DSI's did not address the consequences to BPA customers of the loss of the Hanford resource for the balance of the contract term, to 1993. The DSI's did not evaluate the possible loss of revenue due to the current surplus compared to the possible loss of a 19 mill/kWh resource in future years.

The DSI's admit that WNP-2 should be completed. They claim that BPA may not recover revenues greater than the incremental costs of running WNP-2, but they do not provide any analysis to back up their theory. Mizer, DSI, E-DS-13, 24-30.

Decision

Given the relatively low cost of Hanford and WNP-2 (less than the 7(b) rate), the load uncertainties over the next 10 years, and the opportunity to market the resource at a rate above its costs, BPA continues to include Hanford and WNP-2 as resources for rate purposes.

b. Colockum

Issue #1

How should BPA treat Chelan County PUD's net requirements with regard to Colockum Transmission Company and allocation of BPA energy to Colockum?

Summary of Positions

Chelan County PUD, a generating public utility, traditionally includes the load and resources for Colockum Transmission Company in its load and resource balance for planning purposes (PNUCC Long-Range Projection of Power Loads and Resources, August 1982). BPA rebuttal testimony describes the procedure for determining the purchase of energy by Chelan under Chelan's Power Sales Contract with BPA. Fuqua, BPA, E-BPA-43R, 5. This testimony states that BPA does not sell any firm power to Colockum under a firm Power Sales Contract. This procedure of not selling firm power to Colockum is followed when developing a load and resource balance for Chelan County.

The Public Generating Pool (PGP) claims that BPA included Colockum as a load in nongenerating pool of public utilities. Garman, Opatrny, Knitter, Sunday, Whaley, Lubking, and Grisson, PGP, E-PG-01, 8a. PGP then reduced the nongenerating pool by the Colockum load in their version of the COSA. The PGP claims that Colockum is not a load of either BPA or Chelan even though the Colockum load is included in Chelan's load. Garman, et al., PGP, E-PG-06R.

Evaluation of Positions

BPA, in the initial Loads and Resources Study, did not include Colockum load and resources in the Chelan load and resource balance. Fuqua, BPA, E-BPA-34R, 5. BPA did not allocate any firm energy to Chelan for Colockum. Since this problem of a combined load and resource for Chelan and Colockum seems to cause confusion, it would be more appropriate to complete separate balances for the two entities.

The PGP is in error by assuming that BPA included the load of Colockum in the load of the nongenerating public utilities. (This is in conflict with PGP testimony that Colockum is included as a load on Chelan.) BPA defines the forecast process for the nongenerating and small utility forecast in the Loads and Resources Study. BPA, E-BPA-3, 15-17. This methodology builds the nongenerating public's load based on data for 109 utilities and excludes Colockum from the nongenerating public forecast. The PGP is correct in assuming that the Colockum load was included in the Chelan load. However, they are incorrect in their implication that BPA included Colockum load when determining the BPA sale to Chelan under the Power Sales Contract.

Decision

BPA did not and will not allocate any sale of firm energy to Colockum since Colockum has no agreement with BPA for purchase of firm energy. BPA, in the final rates study, has separated Chelan and Colockum into separate load and resource tables.

c. FBS Federal Hydro

Issue #1

How should BPA's test year hydro capability be determined?

Summary of Positions

In the initial proposal, BPA determined test year firm surplus power using a hydro study that shaped hydro generation reflecting a uniform amount of surplus over the 4-year critical period. Pollock, BPA, E-BPA-15, 2. This results in less hydro generation in the first year than in the later years.

Uniforming the surplus reflects a medium or average set of conditions which would prevail in the test year. Pollock, BPA, TR 4005. It was recognized that actual operation decisions could be quite different. Pollock, BPA, TR 4006.

The PGP, the Public Power Council (PPC), and the Association of Public Agency Customers (APAC) argue that BPA should assume a constant annual output from the Federal hydro system for definition of Federal base resources. Garman, et. al., PGP, E-PG-06R, 6-7; Cook, APAC, E-PA-08R, 17. These parties contend that the 42-month critical period average hydro represents the full capability of the hydro system. Garman, et al., PGP, E-PG-6R, 6. These parties argue that BPA's initial proposal violates the Regional Act, the Power Sales Contract, and the Stipulated Settlement in PPC v. Johnson, 9th Cir. No. 81-7806, because it did not allocate the full capability of the Federal base system resources to Priority Firm (PF) customers, before allocating exchange costs to the PF customers' rate pool.

The DSI's argue that rates must be developed in anticipation of proposed operations and that levelizing hydro over the critical period is contrary to BPA's stated objectives of (1) lowest possible rates consistent with sound business principles; and (2) utilizing the operational flexibility of the hydro system to enhance the marketability of the surplus. Reply Brief, DSI, R-DS-01, 12-15.

Evaluation of Positions

The issue of Federal hydro system capability in the test year centers on what assumption BPA should make concerning the operation of the federal hydro system during the test year, and its effect on surplus firm power. BPA faces a substantial surplus of firm power, and projects that it will be unable to market the entire surplus in the test period. Pollock, BPA, E-BPA-15, 1-8. BPA further projects that the surpluses will gradually decline year-by-year. Id.

Section 7(b)(1) of the Regional Act states that PF customers are served first with FBS resources, then with exchange resources, and then with other resources. The rate or rates charged PF customers "shall recover the costs of that portion of the Federal Base System resources needed to supply such loads until such sales exceed the Federal Base System resources." 16 U.S.C. §839e(b)(1) (Supp. V 1981). Section 3(10) of the Regional Act defines Federal base system resources as including "the Federal Columbia River Power System (FCRPS) hydroelectric projects; . . . ." 16 U.S.C. §839a(10) (Supp V 1981).

The Federal hydro system is a flexible system that has the physical capability to shift energy production between hours, days, months, and years. Under the 42-month critical period system planning provisions of the Coordination Agreement, there is an ability to extract more hydro generation in 1 year, provided BPA is willing to accept having less generation in another year. The Federal hydro system has more operational flexibility to follow loads than a thermal system. Pollock, BPA, TR 4225, 4226. The Federal hydro system, is therefore, not the same as a similarly sized thermal generating system.

Determining the full capability of the hydro system requires more than applying a plant factor to the nameplate rating of the system. As is evidenced by the discussion in this proceeding, determining the capability of the Federal hydro system for 1 year is very complex and subject to various interpretations. The combined Federal and non-Federal hydro system is operated over the critical period in a manner that follows the area's firm load. Pollock, BPA, TR 4225.

Therefore, determining the full capability of the Federal hydro for the test period falls within the discretion of the Administrator, based on sound business judgment. Nothing in the Regional Act specifies the megawatt capability of the Federal hydro system BPA must determine to be available in the test year for ratemaking purposes. Hence, contrary to the preference customers' assertions, BPA is not required by the Regional Act to use the critical period average Federal hydro capability to determine the size of the FBS in the test period.

The DSI's are equally incorrect in asserting that BPA has "no right" to shape into the test year more resources than necessary to meet forecast firm load. Reply Brief, DSI, R-DS-01, 14. BPA's ratemaking assumption concerning the planned operation of the Federal hydro system must be consistent with BPA's obligation to keep rates as low as possible consistent with sound business principles. As long as the planned hydro operation is prudent, BPA has fulfilled its statutory obligation.

The PGP contends that BPA's allocation of costs in the initial proposal violates section 7 of the Power Sales Contract. Opening Brief, PGP, B-PG-01, 4. The PGP's contractual argument is without merit. Section 7 of the Power Sales Contract does not govern cost allocation for the purpose of determining rates. However, if section 7 of the contract governed, BPA's cost allocations in the initial proposal would still be proper because the capability of the Federal hydro in the test year was determined in a manner consistent with section 7(c) and 7(d) of the Power Sales Contracts.

As stated in the title, section 7 of the Power Sales Contract governs: "Allocation Provisions in the Event of Planning Insufficiency." These provisions delineate how the firm capability of the FBS is to be calculated in the event that BPA does not have sufficient power to meet all loads, and must essentially ration power among its firm power customers. Section 7(a) of the Power Sales Contract states:

> If Bonneville determines for any Operating Year that it cannot on a planning basis acquire sufficient resources to fully supply Bonneville's estimated obligation to the Purchaser or any member of the Purchaser's class of Customers and Bonneville's estimated commitments to other Customers whose supply from Bonneville is not subject to restriction in favor of the Purchaser, Bonneville may issue a written notice of restriction to the Purchaser and its class of Customers for such Operating Year.

Section 7(c)(1) of the Power Sales Contract states that the FBS shall be calculated from "the firm capability of the Federal Columbia River power system hydroelectric projects . . ." Section 7(d) of the same contract provides:

> The firm capability for a future Operating Year of the Federal base system resources shall be determined by using streamflows to generate electric power and energy within the constraints on use of the rivers due

> to irrigation withdrawals, navigation, recreation needs, minimum streamflows, fisheries and wildlife operations and other authorized uses. Such capability shall be determined by using such resources' contribution to Bonneville's Firm Load Carrying Capability. Such contribution shall be determined in the same manner as specified in section 16(b)(1) for determining the contribution to Assured Capability of the Firm Resource of a Customer which is included by such Customer in Coordination Agreement planning.

In contracts, as in statutory construction, definitions should be placed where they are most easily found, and where a term is applicable in only one section of a document, it should generally be defined there. A term that is used throughout a document should be defined at the beginning. See 1A SANDS, Sutherland Statutory Construction §20.09, 496 (4th Edition). There is no description or definition of how to calculate the firm capability of the FBS in the general definitions section of the Power Sales Contracts. Elsewhere in the Power Sales Contract exhibits, where the term Federal base system was used in the context of insufficiency allocations, there is a direct citation to the section 7 description. For instance, Exhibit D of the Power Sales Contract contains the following definition: "C = The firm energy capability . . . of the Federal base system resources described in section 7(c) and 7(d)."

By contrast, Exhibit B of the same Power Sales Contract includes a Part C entitled "In Reference to Rates." Section 8(1) therein makes no reference to the description used in the case of insufficiency allocations. Section 8(1) reads:

> (1) Allocation of Exchange Resources. The energy or capacity . . . shall be allocated at the cost thereof to Customers purchasing Firm Power . . . to the extent that the load requirements of such Customers exceed the amount of Federal base system resources, including replacements thereto, determined to be available for ratemaking purposes. (emphasis added).

The above comparison shows a clear distinction in the Power Sales Contract between the listing of Installed Capability to be used in calculating the firm capability of the FBS for purposes of allocation in the event of planning insufficiency, and the determination of Federal base system resources available for ratemaking purposes. Sections 7(c) and 7(d) of the contracts govern how BPA would calculate the full capability of the FBS in order to determine a customers' contractual entitlement to power in the event of planning insufficiency. However, when rates are established, BPA allocates costs, not power. Section 7 of the Power Sales Contract does not govern how BPA determines the capability of FBS resources for the purposes of cost allocation.

If the parties to the contracts intended the provisions in section 7 of the Power Sales Contract to govern calculation of FBS capability for ratemaking purposes, the language "determined to be available for ratemaking purposes" would not have been included in section 8(1). Instead, section 8(1) would refer back to sections 7(c) and 7(d) of the contract. Section 8(1) further supports the point that determining the capability of the FBS for ratemaking purposes is within the Administrator's discretion.

Even if section 7 of the Power Sales Contract applied to cost allocations, the language of the contract does not require BPA to assume for ratemaking purposes any specific capability of the Federal hydro system. Section 7(c) of the contract simply requires that the FBS include the "[f]irm capability of the Federal Columbia River Power System hydroelectric projects . . . ." Section 7(d) of the contract provides that the firm capability "shall be determined by using such resources' contribution to Bonneville's Firm Load Carrying Capability." Thus, section 7 of the contract simply requires BPA to calculate the capability of the hydro in a manner consistent with the calculation used for Coordination Agreement planning. Levelizing hydro output over the critical period, or levelizing the surplus, is consistent with Coordination Agreement planning.

The preference customers also contend that the energy cost allocation in BPA's initial proposal breaches the Stipulation for Settlement in PPC v. Johnson, 9th Cir. No. 81-7806. Exhibit A to that settlement provides: "Any costs, allocated in accordance with section 7(g) of Pub. L. No. 96-501, due to the sale of or inability to sell prior to July 1, 1985, excess electric power acquired under section 5(c)(2) of Pub. L. No. 96-501 shall not be allocated to the rates for the general requirements of public bodies, cooperatives and Federal agencies." The PGP argues that BPA would violate the Stipulated Settlement if it assumed an operation of the hydro system that levelized the surplus (rather than the hydro) over 42 months.

BPA's assumption in the initial proposal that the hydro system would be operated so the projected surplus was levelized over the 42 months does not allocate to preference customers in accordance with 7(g) of the Regional Act excess electric power acquired pursuant to the exchange. Pollock, BPA, E-BPA-15, 3-8. The 8(1) settlement does not preclude BPA in its cost allocations from reflecting sound business assumptions concerning the planned operation of the hydro system.

None of the energy costs allocated to exchange resources that BPA projects it will be unable to recover through firm power sales in the test year, have been allocated in accordance with section 7(g) of the Regional Act. The preference customers' interpretation of the Stipulated Settlement requires ignoring the phrase "in accordance with section 7(g)." A contract must be interpreted to give meaning to all its express terms. Washington Metropolitan Area v. Mergentime Corp., 626 F.2d 959 (D.C. Cir. 1980).

Despite the lack of merit to the preference customers legal positions, BPA finds merit in PGP's suggestion that it is reasonable to assume, for rate purposes, a levelized hydro output over the 42-month critical period. The Administrator has a statutory obligation to keep his overall rates as low as possible consistent with sound business principles. 16 U.S.C. §839e(a)(1) (Supp. V. 1981). Utilizing the operational flexibility of the hydro system to enhance the marketability of the surplus is a prudent business decision. Levelizing hydro output will produce more energy in the first year of the critical period than would have been produced by levelizing the year-to-year surplus. However, levelizing hydro provides sufficient energy over the remaining years of the critical period to prudently support the sale of 700 megawatts of firm surplus sales in years 2, 3 and 4 of the critical period.

BPA projects that it will have substantial firm surplus in the test year, and that the size of the surplus will decline over the critical period. BPA, E-BPA-3, Attachment 2, 528-534. Prior to this rate case, load/resource planning generally has been done under anticipated deficits growing year-by-year, rather than declining surpluses. Under the Coordination Agreement, power system operations are planned for a critical period (i.e., 42 months). Under a growing deficit case, the hydro system is operated to maximize available energy during the 42-month period. This method produces roughly the same amount of energy each year of the critical period. However, there might be an advantage to using an ability to shape hydro capability to move deficits from one year to another depending on the costs and availability of resources to fill deficits or the opportunity to implement an economical shift.

Under a situation with gradually declining surpluses, a prudent planning strategy can be quite different. Generally, if it is anticipated that substantial multiyear sales of surplus may be made, it would be advantageous to shape the output of the hydro system in a manner that will ensure prospective purchasers of firm surplus that BPA will have sufficient resources over the 42-month period to support anticipated long-term sales of surplus firm power.

It is reasonable to assume that 700 average megawatts of surplus firm power can be marketed over the 42-month critical period. Pollock, BPA, E-BPA-15S, 4. To support those anticipated sales BPA should leave about 700 average megawatts firm surplus in years 2, 3, and 4 to assure sufficient surplus was available to cover expected sales. Id.

BPA reviewed the results of PGP's suggestion that the hydro ouput be levelized over the critical period. BPA found that a levelized hydro output will leave sufficient surplus for BPA to shape resources between years 2, 3, and 4 of the critical period to prudently support anticipated firm surplus sales of 700 average megawatts during each of those years. BPA has been urged to take steps that will enhance the marketability of BPA's firm surplus. Opening Brief, DSI, B-DS-01, 6-17. A levelized annual hydro output reflects a reasonable system operation assumption and is consistent with enhancing the marketability of the firm surplus.

The DSI's assert that assuming a levelizing hydro output will waste a resource that could otherwise be saved. Reply Brief, DSI, R-DS-01, 13. This assertion oversimplifies the competing considerations that must be weighted to determine a prudently planned operation of the hydro system when establishing rates.

It is prudent to leave as much firm surplus in the first year of a critical period as possible, as long as there is sufficient firm power in later years to support multi-year firm sales. Pollock, BPA, E-BPA-15, 4. Although hydro operations are planned assuming critical water, there is little likelihood that reservoirs will not refill during the critical period. Id. Therefore, firm energy held in reservoirs for sales in later years of the critical period is likely to be wasted. Given the uncertainties concerning future markets and the likelihood of refill, the Administrator must balance the likelihood of wasting energy saved for later years against the possibility that energy generated by the hydro system in the test year will not be able to be marketed.

Uniforming the surplus, as assumed in the initial proposal, would leave more than 700 average megawatts of firm surplus in each of years 2, 3, and 4. This projected operation would be prudent if BPA reasonably could project greater firm surplus sales in years 2, 3, and 4. However, current projections do not support this assumption. Therefore, it would be imprudent to assume that more energy will be stored for later sales. Levelized hydro output minimizes the potential of wasting energy due to refill, yet leaves sufficient firm power in the later years of the critical period to support projected firm surplus sales in a prudent manner.

Decision

To establish rates, BPA has the legal authority to define the Federal hydro capability in the test period in a prudent manner. In making that determination, BPA should consider matters such as the operational requirements of the Pacific Northwest Coordination Agreement and whether BPA faces a firm power deficit or surplus over the critical period. In the test year, an important consideration is the surplus power market. In this case, adopting the PGP proposal to assume levelized hydro output over the 42-month critical period is a prudent planning assumption for determining rates. Assuming levelized hydro provides sufficient energy over the critical period to prudently support anticipated long-term sales. Therefore, BPA's rates in this case will be based on the assumption that Federal hydro will be levelized over the critical period.

Issue #2

Should BPA use a 39-month average or 42-month average to determine the average firm hydro generation over the critical period?

Summary of Positions

Section 4(h) of the Regional Act requires BPA to take specific actions to enhance the Columbia fisheries. For the first time, BPA is implementing the Water Budget prescribed by the Pacific Northwest Power Planning Council's

Columbia River Basin Fish and Wildlife Program. In the Loads and Resources Study, a method was required to determine the quantity of unmarketable firm energy as a result of the Water Budget in the 3 months of May included in the 42-month critical period. BPA, E-BPA-3, 64-66. Inclusion of the Water Budget reduces the firm energy load carrying capability of the Federal hydro system by 332 average megawatts. Dean, BPA, E-BPA-19, 3. In order to enhance the fisheries, BPA will store water in previous months so that there will be sufficient water available in May to meet the Water Budget requirements. This storage of water to enhance the fisheries causes the hydro system to either generate substantially more energy in May than is necessary to meet firm loads, or to spill water. Dean, BPA, TR 7769. Most of this reshaped firm energy becomes secondary energy. However, this secondary energy is available in months when it is unsaleable. Dean, BPA, E-BPA-19, 6. This impact of the Water Budget necessitates changes in the usual method of computing firm energy.

In the initial proposal a firm surplus for the region and the Federal System was calculated as the difference between the average 39-month critical period generation (42-month critical period excluding the 3 May fish flow months) and the average 42-month critical period load. However, the monthly load and resource analysis contained in the Loads and Resources Study, shows the total generation in Mays for each utility or for subgroups of utilities. BPA, E-BPA-3, Attachment 2, 206-372, 519-631.

The PGP claims that the total generation in the three May months of the critical period should be included in the calculation of the critical period firm surplus. Garman, et al., PGP, E-PG-06R, 6. PGP claims that, unless the three May months are included, BPA is improperly ignoring the Federal hydro system capability in May that can be used to meet firm load. Opening Brief, PGP, B-PG-01, 8. The use of a 42-month critical period average for hydro capability, rather than a 39-month average, results in a larger FBS. PGP claims that the 42-month figure should be used to determine the size of the FBS resource when allocating costs to the 7(b) rate pool. The PGP also says that the Federal system must use full firm capability. Opening Brief, PGP, B-PG-01, 6. PGP also indicates that the difference between BPA's firm load requirements in May and the amount of water needed for the Water Budget would not be available for firm power production. Opening Brief, PGP, B-PG-01, 8.

Evaluation of Positions

BPA's initial proposal recognized that May energy generation will be a statistical aberration that has little relationship to how BPA would operate the system to meet firm loads in the absence of the Water Budget. The Water Budget causes BPA to plan significantly more water releases in May than is necessary to meet projected firm loads. Fuqua, BPA, E-BPA-3, 214-216, 528, 530. These water releases are required to avoid impacts the hydro system would otherwise impose on the migration of anadromous fish. Since the Water Budget is mitigating environmental impacts imposed by the Federal hydro system, the impact of the derating of the hydro system should properly be borne by customers allocated FBS costs. Those customers derive the primary rate benefits of the Federal hydro system.

The region is so surplus in May, there is no possibility of firm sales to other utilities in the region. Moreover, the Southwest utilities are aware of the energy situation in May and are not interested in purchasing energy during this month on a firm basis. Therefore, since there are no markets for this energy on a firm basis, it must be marketed as nonfirm. For defining FELCC, May firm surpluses are treated as equal to the average firm surpluses of the other 39 months. Any FELCC above that level will either be spilled or sold as nonfirm energy.

The PGP claims that the additional May energy must be included in the annual average calculation, even though there exists a large quantity of energy in May not being generated to meet firm loads. The PGP argues that all firm energy for the 42-month critical period should be included in the FBS even though there is no market for this May energy. It is not appropriate to include this May firm energy in the 7(b) rate pool, if it is spilled or sold as nonfirm. If BPA adopted the PGP's proposal, the negative rate impacts of the Water Budget would be imposed on BPA's other firm power customers, rather than only the 7(b) customers. Consistent with section 7(g) of the Regional Act, it is equitable to impose the cost of derating the hydro system on the 7(b) customers, since they realize the rate benefits of the Federal hydro system. The PGP is inconsistent in its arguments by admitting that some of the May capability could be considered unavailable for firm power production, while arguing that all of it should be included as an FBS resource.

Decision

BPA will use a 39-month average for determining the uniform hydro capability during the test year. The use of the 39-month average for the hydro system is a valid and appropriate method of determining a realistic level of FBS resource for the test year. This method eliminates the effect of the significant additional amount of hydro generation in May for the purpose of meeting the Water Budget requirements, which is a requirement against FBS resources. In addition, it is appropriate to include only enough hydro generation in May to meet firm loads. This is consistent with the PGP's concession that the generation in May, needed for the Water Budget in excess of firm loads, can be excluded for determining firm resource capability.

Issue #3

Is it proper for BPA to list 50 percent of Hanford output as a Federal base system energy resource?

Summary of Positions

PGP argues that 100 percent of Hanford output must be included in the FBS for ratemaking purposes. PGP asserts that because sections 7(c) and 7(d) of the Power Sales Contract include 100 percent of Hanford in a list of Installed Capability in the list of Federal Base System Resources, BPA must use all of that Installed Capability as the FBS resource for purposes of cost allocation in ratemaking. Opening Brief, PGP, B-PG-10. APAC argues that because BPA staff "readily concedes that the size of the FBS is determined differently for rates and operational purposes" and "also admits that the Power Sales Contracts require the FBS to be defined by resources, not loads," Hanford's entire 860 megawatts installed capability must be included in the FBS for purposes of cost allocation. Opening Brief, APAC, B-PA-01, 67.

Evaluation of Positions

Section 7(c) of the Power Sales Contract provides that the "firm capability of Federal base system resources shall be calculated from . . . (2) the firm capability of resources listed below . . . . " The list includes Hanford and shows an Installed Capability of 860 megawatts. Section 7(c) governs how BPA must calculate the capability of FBS resources to determine customers' contractual entitlements to power in a period of planning insufficiency. See, discussion supra, above.

BPA is not required to include the entire 860 megawatt Installed Capability of Hanford in the FBS. Subsection 7(c) of the Power Sales Contract states only that the firm capability of the FBS will be calculated from the firm capability of the listed resources. It then lists the three types of resources which contribute to the FBS: Federal hydroelectric projects, resources available under long term contracts in effect at the time of passage of the Act, and resources acquired to replace reductions in the firm capability of FBS resources. The list of contractual resources shows Hanford's installed capability (860 MW) but does not state that the installed capability is equivalent to Hanford's firm capability for FBS purposes. Section 7 of the Power Sales Contract does not require that all of Hanford's Output be considered an FBS resource.

BPA did agree that subsection 7(c) of the Power Sales Contract lists Hanford's Installed Capability at 860 megawatts and that a lesser figure was used in the Loads and Resources Study calculations. Fuqua, BPA, TR 4145, 4146. BPA's witness further stated that in his reading of the Power Sales Contract, subsections 7(c) and 7(d) define the capability of the FBS in terms of resources, and not in terms of loads. Fuqua, BPA, TR 4223, 4224. BPA's witness did not and was not asked to testify as to the legal effect of the contract as a whole, and made no statement regarding the size of Hanford's contribution to the FBS.

Decision

BPA's initial proposal correctly lists one-half of Hanford Output as an FBS energy resource for ratemaking purposes. The AEC Appropriations Act of 1982, Pub. L. No. 87-701, required the Supply System to offer 50 percent of the electric energy produced by Hanford to private organizations, and 50 percent to public organizations. This statutory entitlement was embodied in the original Hanford agreements, in which five investor-owned utilities backed 50 percent of the Hanford facility and became entitled to that share of Hanford's Output. Under the 1963 Hanford Exchange agreements, the IOU's and the public participants exchange 100 percent of Hanford's Project Output (power/energy) for firm BPA energy and capacity. Contracts 14-03-35345 through 14-03-35363, and 14-03-35569 through 14-03-35625. By terms of a 1974 Letter Agreement, BPA has committed 50 percent of Hanford's Project Output to be available to five IOU's at the incremental cost to the Supply System of producing that energy, for the duration of Hanford operation. Letter Agreement of May 8, 1974, among BPA, the Supply System, and five IOU's. Therefore, only 50 percent of Hanford Output was available to the Administrator under long-term contracts when the Regional Act was passed, and only 50 percent of Hanford Output can be considered an FBS resource.

Finally, BPA's pre-Regional Act obligation to deliver energy to the IOU's pursuant to the 1974 Letter Agreement is carried out by the 1983 Hanford Extension Agreement. Contract DE-MS79-83BP90951. Because the energy must be delivered at its incremental cost of production, the obligation is not a load to which costs allocation pursuant to section 7(g) of the Regional Act, or other costs may be allocated. This fact is accounted for in the COSA by listing only one-half of Hanford's output as a resource. Such listing is consistent with COSA treatment of Columbia Storage Power Exchange (CSPE) obligations, testified to as proper by the PGP. Lubking, PGP, TR 8195, 8196. Whether or not BPA's contract with the IOU's is "a proper sale," Lubking, PGP, TR 8196, cannot be raised collaterally in this proceeding. Were BPA to have accounted for Hanford by listing 100 percent of Hanford output as a resource, it would have been necessary to subtract an IOU load equal to one-half of Hanford as well. The resulting effect on cost allocation would be nearly identical.

d. Displacement of Exchange Purchases

Issue #1

Should rates be established based on the assumption that BPA can displace exchange purchases from utilities?

Summary of Positions

The DSI's argue that BPA should establish rates based on the assumption that exchange purchases will be displaced to eliminate the projected firm power surplus. Mizer, E-DS-13, 19-23. They contend that BPA cannot lawfully continue purchasing exchange power if those purchases will create a surplus on BPA's system. DSI Prehearing Brief, 33-37. The DSI's contend that declining to purchase exchange resources would be simple to implement. Reply Brief, DSI, R-DS-01, 26. The DSI's contend that BPA's revenue requirement in the test year would be reduced by $141.6 million if BPA declined to buy a total of 400 average megawatts of exchange power from two investor-owned utilities with the highest average system costs. Mizer, DSI, E-DS-13, 19 and Attachment B.

Evaluation of Positions

While the DSI's have asserted that BPA could eliminate the projected firm surplus by refusing to purchase exchange power from utilities, no complete proposal has been developed. Absent from the DSI's suggestion is a delineation of how BPA would determine which exchange purchases it should terminate during the test period. Attachment B to E-DS-13 contains an example purporting to calculate the gross savings to BPA if 400 average megawatts of purchases were assumed to be displaced from two investor-owned utilities. However, the DSI's did not suggest any objective criteria that would support a displacement of exchange purchases from these two utilities, or any utility for that matter. In their reply brief, the DSI's argue that BPA can determine the most expensive resources and acquire resources accordingly. Reply Brief, DSI, R-DS-01, 27. While the DSI's contend that BPA is required to displace exchange purchases in a period of surplus, the DSI's admit that their proposal would simply shift BPA's surplus to the exchanging utilities. Mizer, DSI, E-DS-13, 20. As for legal justification, the DSI's have not developed a thorough analysis demonstrating that the displacement proposal is legally sound, given the requirement in section 5 of the Regional Act that BPA exchange power with the region's utilities, when offered, for the benefit of residential and small farm customers. The DSI's simply assert that BPA has a legal obligation to decline purchases during times of surplus.

Decision

Displacement of exchange purchases is a serious issue that should not be addressed on the basis of the unsubstantial record compiled by the DSI's. The DSI's have forwarded a novel, but untested legal theory. It would not be prudent for BPA to establish rates based on the assumption that some exchange purchases could be displaced during the test period. There is no precedent for BPA to rely on. If BPA establishes rates in reliance on the DSI's legal theory, and it is later established that their legal theory is without merit, BPA's rates will not be set at a level sufficient to recover total system costs and repay the Treasury.

e. Marketable Capacity

Issue #1

Does BPA have marketable excess capacity available from its resources during the test year?

Summary of Positions

In the initial proposal BPA did not specifically identify the level of saleable capacity that could be produced by its resources during the test year. The WWPUD's suggest that BPA should identify the costs of unsold capacity. Hutchinson, et al., WWPUD, E-WW-01, 21. This suggestion implies that BPA must determine the level of capacity generation available, and from that, the amount of capacity in excess of projected loads, and hence that which is unsold. The APAC argues that there is capacity beyond firm loads. Reply Brief, APAC, R-PA-01, 9.

Evaluation of Positions

Although BPA can identify the nameplate capability of its resources, BPA does not know how much of this identified capability is marketable, after firm loads are served. Fuqua, BPA, TR 4140-4142, 4978-4980, 4994-4995. There are various ways to determine the amount of capacity on the system, and risk analysis must be undertaken to determine the amount of capacity that is prudent to sell. Fuqua, BPA, TR 4141. Capacity resources are identified in the COSA merely as the starting point in allocating capacity costs. These resources are not, however, intended to be a measure of the capacity that BPA has available to market. BPA, E-BPA-5, G-32. This would exaggerate the amount of marketable capacity BPA has on its system that is not being, or cannot be, sold in the test year. The COSA identifies 4,620 megawatts of Federal base system machine capability in excess of capacity loads. BPA, E-BPA-5, G-32. No party has asserted that BPA's system has 4,620 megawatts of marketable capacity in excess of projected capacity loads.

The PPC and the PGP argue that exchange resources are not needed to serve Priority Firm customers' capacity loads because the capability of Federal base system resources identified by BPA in the first step of the allocation process exceeds Priority Firm customers' capacity loads. Garman, et al., PGP, E-PG-06R, 8. Their argument ignores the fact that the capability identified in the first step of the allocation process is not the quantity of capacity known to be marketable, or even useable to meet firm loads in the test period. BPA has not completed, but is in the process of making a study to determine how much of the capacity in excess of its firm commitments is marketable. Fuqua, BPA, TR 4141. This study is considering the impact of the sustained peak reductions, as well as, the potential loss of energy due to the inability of the system to accept the nighttime return from capacity sales. Both of these factors could reduce to zero the marketable capacity beyond what is now used to meet firm loads. BPA does not have an accurate projection of the amount of capacity it can market. Lacking such a demonstration, it would not be responsible to assume, for purposes of determining rates, that all machine capability identified in the COSA is marketable capacity. Furthermore, even the COSA determinations of excess machine capability in the test year fluctuate widely over the 12 months.

Decision

In the absence of a study clearly demonstrating that BPA has marketable capacity in excess of its firm commitments, it would not be prudent to establish rates based on the assumption that additional capacity is available in the test period.

f. Marketability of Surplus

Issue #1

How much of the Federal firm power surplus should BPA project can be sold at the Surplus Firm Power Contract rate or the Surplus Firm Energy rate?

Summary of Positions

BPA's initial proposal estimated that of the 828 average megawatts, BPA, E-BPA-3, 65, of firm surplus available in OY 1985, 400 average megawatts could be sold at the Surplus Firm Power rate in all months except May and June. Pollock, BPA, E-BPA-15, 6. This would result in an average of 333 average megawatts over the 12-month period (July 1984 to June 1985) that would be marketable at fully allocated costs under the Surplus Firm Power Contract rate or Surplus Firm Energy rate. These estimates were based on a combination of sales experience in 1983 and judgment regarding the progress at that time of power sales negotiations. Pollock, BPA, E-BPA-15, 6.

In supplemental testimony, BPA increased the estimated amount of surplus marketable at the Surplus Firm Power rate or the Surplus Firm Energy rate to an annual average of 700 megawatts for the period July 1984 to June 1985. This updated marketability estimate was based on the current status of negotiations with prospective purchasers, which were more optimistic than at the time BPA filed the initial proposal. Pollock, BPA, E-BPA-15S, 3-5. BPA noted that it was close to finalizing a 175 average megawatt sale with Western Area Power Administration. Pollock, BPA, E-BPA-15S, 4.

The DSI's assert that BPA should assume, and must assume for ratesetting purposes, that it can sell all of the Federal firm surplus power in a manner that collects the fully allocated costs of the surplus firm power. Mizer, DSI, E-DS-13, 1; Opening Brief, DSI, B-DS-01, 98-100. The DSI's suggest a series of actions they believe would enhance the marketability of firm surplus power. Mizer, DSI, E-DS-13, 2.

Evaluation of Positions

BPA's assumption that 700 average megawatts of firm surplus can be sold at the Surplus Firm Energy rate or the Surplus Firm Power rate is based on sales experience in FY 1983 and the current status of negotiations with prospective purchasers. Between the filing of the initial proposal and the supplemental testimony, new information made it prudent for BPA to increase the assumption from 333 average megawatts to 700 average megawatts.

Contrary to assertions of the DSI's, it would be unreasonable and imprudent for BPA to assume, in establishing rates, that it will sell all of its available surplus firm power resources at either the Surplus Firm Power or the Surplus Firm Energy rates. BPA has had extensive discussions with several utilities in the Southwest and has concluded that the most likely prospect for selling the firm surplus at proposed rates is 700 megawatts. This is less than the amount of firm surplus available for sale. Pollock, BPA, E-BPA-15S, 4.

In FY 1983, BPA assumed it could sell 548 average megawatts, yet in the first 4 months only 73 average megawatts were sold at the Surplus Firm Energy rate. Pollock, BPA, E-BPA-15, 7. Dispite the experience in early FY 1983, a slightly more optimistic estimate for ratemaking purposes is appropriate at this time, because extraordinary circumstances had some impact in FY 1983, and because progress has been made in marketing surplus power with prospective purchasers. Pollock, BPA, E-BPA-15, 6-7. These changes, however, do not warrant assuming sales of all surplus firm power. The DSI's witness acknowledged that it would be important, for business planning purposes, to consider historic sales experience when making marketing projections. Mizer, DSI, TR 6992. The DSI's witness also acknowledged that there were no specific developments that make it prudent for BPA to assume it will market all, or nearly all, available firm surplus in the test period. Mizer, DSI, TR 6992. Rather, he noted that current marketing efforts are "likely to be met with somewhat more success" than historic experience. Mizer, DSI, TR 6992. PGP witnesses also urged BPA to assume that 1500 average megawatts will be sold in the test year, but did not point to specific sales that would support that assumption. Garman, et al., PGP, E-PG-06R, 8-9.

No party pointed to specific surplus sales that would support BPA assuming that all marketable firm surplus will be sold in the test period. Optimistic sales projections may hold down some customers' rates in the test year, but if those projected loads do not materialize, BPA will be unable to meet treasury obligations. BPA has a statutory obligation to establish rates at a level sufficient to meet total system costs and repay the treasury. The Federal Energy Regulatory Commission (FERC), in its "Order Confirming and Approving Rates On A Final Basis", 23 FERC 4161,378 at 61,797 (June 15, 1983), stated that BPA's 1982 load projections were "over-optimistic," and resulted in unduly excessive estimates of sales.

Decision

Based on experience to date, knowledge and study of the marektplace, and progress of negotiations with specific prospective purchasers, it is reasonable to assume that 700 average megawatts of the surplus can be marketed at the Surplus Firm Power Contract rate or the Surplus Firm Energy rate during the test period.

None of the parties pointed to specific projected firm surplus sales that would make it prudent to assume more that 700 average megawatts will be sold in the test year. In light of FERC's criticism of overly optimistic sales projections in the 1982 rate proceedings, it would not be prudent to establish rates based on the assumption that all firm surplus will be sold in the test year.

3. Conservation

Conservation program levels incorporated in BPA's initial proposal as supplemented by E-BPA-14S are $249.5 million for FY 1983, $192 million for FY 1984, and $189 million for FY 1985. Several parties raised the following issues regarding conservation program levels during the test period.

Issue #1

Should BPA revise conservation program levels based on factors listed in BPA's Notice of Suspension of The Near-term Resource Policy Development Process?

Summary of Positions

In the initial proposal, BPA stated that a reanalysis of program levels was made in response to, among other things, changing load/resource and surplus sales forecasts, and that the program levels derived reflect a balance between long-term needs to meet acquisition targets and short-term surplus and rate concerns. Hickey, BPA, E-BPA-14, 2.

The PNGC suggested that BPA should reevaluate conservation program levels based on the factors listed in BPA's Notice of Suspension of the Near-term Resource Policy Development Process. Specifically, these factors are: (1) lower short-term load forecasts; (2) reduced revenues from reduced power sales; and (3) inability to sell surplus power. Johnson, PNGC, E-PN-5, 1-2. This position also was taken by Chelan, Douglas, and Grant County PUD's. Lubking, et al., Chelan, E-CH-01, 3-4.

Evaluation of Positions

The factors referenced by the PNGC are important variables to consider in determining resource acquisitions by BPA, including conservation. At the time the Administrator requested BPA offices to review and revise program levels in order to hold down costs, BPA had just finished a reanalysis of those levels. This analysis was based in part on changing load/resource and surplus sales forecasts. Program levels were subsequently revised and incorporated in the initial proposal to reflect these changing conditions. Hickey, BPA, E-BPA-14, 2. Thus, the factors outlined in the Suspension Notice already have been considered in the development of conservation program levels in the initial proposal.

Decision

The program levels incorporated in the initial proposal as supplemented by E-BPA-14S do not require revision based on the factors outlined in the Notice of Suspension of The Near-term Resource Policy. BPA already had considered these factors at the time that all BPA offices were requested to revise program levels in order to hold down costs.

Issue #2

Should BPA revise the 35 mill/kWh conservation ceiling level for consistency with the 20 mill/kWh level used for other resource acquisitions?

Summary of Positions

BPA testified that the primary difference between the 35-mill and 20-mill figures is the ramping requirement for conservation resources. Hickey, BPA, E-BPA-14, Attachment 1. The PNGC recommends that BPA reevaluate the 35-mill/kWh ceiling level identified for conservation resource acquisition in BPA's Near-term Resource Policy to reflect a more current least cost mix (LCM) analysis. Specifically, the PNGC suggests BPA use the LCM runs which produced the 20 mill/kWh used for other BPA resource acquisitions. Also, the PNGC believes a lower ceiling level would bring the supply and demand of conservation program funds into equilibrium. Johnson, PNGC, E-PN-5; Johnson, PNGC, DP 95; Reply Brief, PNGC, R-PN-01, 2-3.

Evaluation of Positions

Although the 20-mill and 35-mill figures are derived from the different LCM runs, the primary difference between the two levels is the ramping requirement for conservation. If acquisition of conservation resources is not commenced ahead of the need, the least cost mix of resources to meet power needs will not be achieved over the 20-year planning period. For resources with this ramping requirement, BPA finds that the 35-mill level is appropriate; for those resources that do not exhibit this requirement, a 20-mill level is more appropriate. Hickey, BPA, TR 4245-4247. While more recent LCM analyses have demonstrated a downward pressure on the 35-mill ceiling, none of these analyses have provided sufficient cause for revising that ceiling. Hickey, BPA, TR 4267-4268. Since conservation programs and their respective incentive levels reflect a levelized cost of at or below 26 mills, a decreased cost ceiling from recent LCM runs would not be a factor in reevaluating acquisition levels. Hickey, BPA, E-BPA-14, Attachment 1.

Decision

A revision of the 35 mill/kWh ceiling level is neither justified nor necessary. Although recent LCM analyses indicate a downward pressure on that level, these analyses do not support a reduction of that level. Also, it would be unlikely that a lower ceiling level would result in reduced program levels, since the cost of BPA's regionwide conservation programs are no greater than 26 mills/kWh.

Issue #3

Should BPA revise conservation program levels based on the assumption that less than 100 percent of the utilities will sign the long-term conservation contract?

Summary of Positions

BPA's conservation program target levels are derived independent of the determination of how many utilities will participate in BPA's programs. It is BPA's goal to acquire the same level of conservation identified for FY 1984 and FY 1985, even in the event that less than 100 percent of the region's utilities participate in BPA's program. Hickey, BPA, TR 4257. Only in the case where a very substantial portion of the region's load is in the service territories of those utilities that do not sign the long-term contract might a reevaluation of funding levels be made. Hickey, BPA, TR 4257-4258.

The Intercompany Pool (ICP) suggests through cross-examination of BPA, that program levels should be revised to reflect the possibility that some utilities will not sign the long-term contract, and consequently funds will not be spent. Hickey, BPA, TR 4254-4258. Seattle City Light (SCL) states that the potential for underrecovery of conservation costs exists if some utilities elect not to sign the long-term contracts. Fiddler, SCL, E-SL-01, 7-8; Reply Brief, SCL, R-SL-01, 19-20.

Evaluation of Positions

Only in the case of substantial nonparticipation in BPA's long-term conservation contract will program levels be reviewed and revised, since the target levels were determined independently of delivery mechanisms. While the ICP asserts that less than 100 percent of the IOU's will participate in the long-term contract, they did not indicate the extent of nonparticipation BPA should project. White, ICP, TR 7586. A significant underrecovery of costs is possible only if a large number of generating utilities do not sign the contracts, and their allocated funds are spent by nongenerating utilities or other entities not paying a contract charge. This scenario is not supported by the record.

Decision

Conservation program levels should not be adjusted for the potential of less than 100 percent participation in the conservation contract. While there is the possibility that not all large generating utilities will sign the long-term conservation contract, BPA's goal is to acquire conservation at the targeted levels consistent with the least cost resource mix. It is not apparent from the record that the potential level of nonparticipation in the long-term contracts will effect BPA's ability to achieve those targeted levels, or create any significant underrecovery problems.

Issue #4

Should BPA not make retroactive payments and adjust program levels accordingly?

Summary of Positions

In BPA's initial proposal, BPA stated that approximately 40 million dollars of FY 1983 funds might be spent for retroactive reimbursement. This is an obligation incurred under BPA's short-term conservation contract. While this obligation is continued under BPA's long-term conservation contract, there are no funds budgeted for retroactive payments in FY 1984 and FY 1985. If any payments are made in those two years they would be on a "funds as available" basis. Hickey, BPA, TR 4330-4335.

The DSI's challenge the statement above, claiming that the long-term conservation contract gives the utilities the option to receive retroactive payments before receiving regular program payments. They also believe retroactive payments are both unwise from a load/resource balance perspective and illegal under the Regional Act. Consequently, retroactive payments should be stopped, and program levels reduced, accordingly. Opening Brief, DSI, B-DS-01, 73-74.

Evaluation of Positions

Retroactive payments do not affect the resource balance during the test period. BPA was obligated in FY 1983 under the short-term conservation contracts to make retroactive payments, and this obligation is reflected in the FY 1983 program levels. However, there are no retroactive payments specified in the 1984 and 1985 funding levels, although the obligation will continue through those years.

While it is true that utilities can receive retroactive payments under the long-term contract, they can only do so at the expense of program funds. Thus, any retroactive payments made during the FY 1984 and FY 1985 period will have no effect on the level of spending assumed for purposes of establishing rates for the 20-month rate period. Retroactive payments have no additional effect on the rate paid by DSI customers because retroactive payments made in FY 1983 are already included in current program levels. Furthermore, BPA has not allocated any conservation costs to the DSI's. See discussion Chapter V, Conservation Allocation, Issue #2.

Decision

No adjustment to program levels used to determine BPA revenue requirement should be made on the basis of retroactive payments. The only funding specified for retroactive payments for which BPA is obligated is in FY 1983. BPA is legally obligated under BPA's short-term contract to make the FY 1983 payments. To the extent the DSI's are attacking BPA's legal authority to make retroactive payments to utilities under either the short-term or the long-term contracts, the DSI's cannot raise a collateral attack on these decisions through this rate adjustment proceeding. There are no funds specified for retroactive payments in the FY 1984 and FY 1985 levels. Thus, even if retroactive payments are not made in those years, program levels used to determine the test year revenue requirement would not be affected. Also, any program payments made will have no effect on the rate paid by the DSI's, since the DSI's are not allocated conservation costs.

Issue #5

Does conservation acquired during the test period improve the quality of service to the DSI top quartile?

Summary of Positions

The PPC asserts that conservation acquired during the test year improves the quality of service to the DSI's by reducing interruptions of service to the DSI's top quartile. The basis for this conclusion is an excerpt from E-BPA-14, Attachment 3, 14. The PPC has interpreted this paragraph to say that BPA is acquiring conservation during this near-term period of surplus because, among other things, it provides value to the DSI's top quartile by reducing potential interruptions of service. The PPC contends that the results of the LCM analysis demonstrating negligible to negative top quartile benefits were a random effect of the SAM model. Wolverton & O'Meara, PPC, E-PP-01, 24; Opening Brief, PPC, B-PP-01, 30-32; Reply Brief, PPC, R-DS-01, 32-33.

BPA contends that the paragraph referenced has been taken out of context, and consequently misinterpreted. In fact, the underlying LCM analysis indicates little to no benefit to the DSI's during the test period in the All Conservation Case scenario. Hickey, BPA, TR 4286-4292; Fuqua & Hickey, BPA, TR 4346-4359.

Evaluation of Positions

The paragraph in question is part of a description of a long-term planning and analytical model. The cited paragraph explains the treatment of the value of conservation within that context. Thus, any conclusions regarding the near term based on a long-term planning model are highly speculative and should be qualified as such. The underlying analysis performed by BPA indicates negligible to negative benefits to the DSI's top quartile during the test period from the All Conservation Case, the scenario which treats conservation as a totally flexible resource. Fuqua, BPA, TR 4351. This finding is due to the combined effect of the probabilistic nature of the System Analysis Model (SAM) and the relative small amount of conservation picked up during the test period when compared to the size of the surplus. Fuqua, BPA, TR 4349. Thus, the level of benefit or disbenefit to the DSI's top quartile during the test period is negligible, and does not appear to exceed the "noise" in the system.

Decision

The PPC's interpretation of the referenced paragraph concerning the value of conservation to the DSI top quartile is incorrect. BPA is not acquiring conservation now to reduce interruptions of the service to the DSI top quartile. BPA is acquiring conservation now to meet long-term acquisition targets with the least cost mix of resources. In addition, the analysis underlying conservation program levels for FY 1984 and FY 1985 does not demonstrate significant benefits during the test period to the DSI top quartile from conservation acquisitions.

Issue #6

Should BPA acquire conservation during the near-term period of surplus under changing prices of surplus firm sales?

Summary of Positions

BPA stated that the analysis underlying the program levels incorporated in the initial proposal addressed a range of scenarios with different assumptions on surplus sales prices. This analysis demonstrated relatively minor effects on the optimal level of conservation acquisition during the test period resulting from variations in these prices. Therefore, BPA maintained that the levels incorporated in the initial proposal, which are consistent with the least cost resource mix, reflect consideration of the potential variability of surplus sales prices. Hickey, BPA, E-BPA-14, Attachment 3, 2.

The PNGC states that conservation program levels should be reduced during the near-term period of surplus because of conservation's adverse impact on the amount of surplus and BPA's inability to market this surplus. Opening Brief, PNGC, B-PN-01, 8-9; Reply Brief, PNGC, R-PN-01, 1-2. This position was echoed by the DSI's and APAC. Opening Brief, DSI, B-DS-01, 72-73; Opening Brief, APAC, B-PA-01, 26.

Evaluation of Positions

While acquisition of conservation in the near-term may increase BPA's surplus firm power and effect the price associated with surplus firm power sales, any reduction of conservation program levels in the test period would thwart meeting BPA's long-term conservation acquisition targets and the least cost resource mix of resources would not be achieved. Also, the SAM analysis performed by BPA shows that decelerating or accelerating conservation acquisition from the rate implied by current levels will increase system cost. Hickey, BPA, E-BPA-14, 6-7. In the case of substantial uncertainty of load/resource and surplus sale forecasts, BPA has developed acquisition strategies that are flexible and can respond to different situations. Hickey, BPA, E-BPA-14, Attachment 3, 2.

Decision

BPA's conservation program levels during the rate period should not be adjusted to reflect changing surplus conditions. While the near-term surplus may be increased, this is an unavoidable consequence if BPA is to acquire conservation at the levels indicated in the initial proposal to achieve the least cost resource mix to meet the long-term needs for power.

4. Resource Acquisitions

Within BPA's overall resource strategy, consistent with the Northwest Power Planning Council's Plan, BPA will expend funds within the rate period for the Resource Development and Acquisitions Program. This program, because of the uncertainty with respect to resource availability and requirements, must retain flexibility in the final application of funds. BPA will exercise its discretion in the use of acquisitions funding, on behalf of the ratepayers, to acquire the most cost-effective and efficient resources if and when a need is identified. This degree of discretion will enable BPA to identify and transact the most economic acquisitions without being obligated to wait until subsequent rate proceedings to make specific proposals. This position conforms with generally accepted, prudent utility practice. No party raised issues with respect to this Resource Development and Acquisitions Program.

C. Revenue Forecast Study

The Revenue Forecast Study (RFS) both initiates and completes the rate development process. At the beginning, the RFS estimates revenues to be recovered prior to the start of the rate period under the current rates. At the end of the process the RFS verifies that, based on projected loads, the proposed rates will recover the needed revenues.

The RFS initially identifies revenues expected to be collected before the rate period begins (i.e., prior to November 1, 1983) using both actual and forecast data. When compared to expected costs for the same time period, this information determines the expected deferral, if any, that will be carried over into the rate period. The deferral then is entered into the Revenue Requirements Study in order to determine the level of revenues needed during the rate period.

Another part of the RFS is the last step in rate development. The RFS uses information developed from the Loads and Resources Study, the Wholesale Power Rate Design Study, the Transmission Rate Design Study, and other sources to project BPA revenues under proposed rates during the rate period (November 1, 1983 through June 30, 1985). This final forecast is used to verify that the proposed rates are adequate to meet BPA's revenue requirement.

The RFS also presents historical sales and revenues for comparison with the current forecasts. Additionally, the RFS consolidates some information used in the Cost of Service Analysis. This includes information that is necessary to develop cost allocation factors used to apportion costs to the individual customer classes, and the Revenue Credits which are revenues expected from some customers or classes of service not subject to rate changes in this rate adjustment.

The RFS uses the output of a number of computer programs. The Average System Cost program disaggregates the loads of public agency customers based on percentages developed from a historical year. This program also estimates the size of the preference agency exchange and the value of the Low Density Discount, and aids in determining the cost of the Exchange Transmission Credit Agreement, the cost of residential exchange resources acquired from Preference Agencies, and the development of conservation contract charges. The Nonfirm Revenue Analysis Program estimates revenue from the sale of nonfirm energy, interruptible sales to the DSI's, Displacement/Energy Broker sales, interchange sales under the Coordination Agreement, and some incidental revenues from wheeling non-Federal power. The Revenue Estimate program combines information from these other programs with information from other studies developed by BPA to support the rate adjustment. Explanations of these programs are contained in Appendices to the RFS. BPA, E-BPA-4. Output from these other studies is contained in documentation supporting the RFS. BPA, E-BPA-4, Attachment 1.

For FY 1983, actual sales and revenues were less than projected in the initial proposal, largely as a result of adverse economic conditions, warmer than usual weather, and unusually heavy precipitation that caused an excess of resources. Also, expected New Resources sales did not occur. However, additional sales and revenues resulted from short-term sales of nonfirm energy to the DSI's, from nonfirm sales to customers of NW preference agencies, and from previously unprojected Energy Broker sales.

For the rate period, projected revenues differ from the initial proposal because of: corrections and additions to residential exchange loads; a revised DSI load forecast; revised assumptions of Surplus Power sales; a decrease in projected New Resource sales; and a revised resource schedule and hydro study. The following issue was raised during the hearings with regard to the RFS that is not covered elsewhere in the Administrator's Record of Decision.

Issue #1

Are BPA revenues during the rate period underestimated because of the omission of NW nonfirm sales, and understatement of sales under the Displacement and Energy Broker rates?

Summary of Positions

The WWPUD's maintain that BPA revenues during the rate period are underestimated. They assert that: (1) revenues from the sale of interruptible power to customers of NW preference agencies are omitted; and (2) nonfirm energy sales at the Displacement and Energy Broker rates are understated. Hutchison, et al., WWPUD, E-WW-01, 49-53.

The WWPUD's also assert that there are 3805 megawatts of Northwest thermal resources that are not displaceable at the Spill rate, but that would be eligible for displacement at the Displacement rate as outlined in the Evaluation. Reply Brief, WWPUD, R-WW-01, 10.

Evaluation of Positions

BPA did not project any revenues from interruptible sales to customers of NW preference agencies in the initial proposal because sufficient data to make the forecasts were lacking. Wedlund, BPA, TR 4690. The assertion that BPA should expect to receive more revenues from displacement of thermal plants than presently projected is unsubstantiated. The WWPUD's have maintained that Energy Broker (EB) sales and revenues are projected by BPA to be substantially greater in FY 1983 than in the test period. Opening Brief, WWPUD, B-WW-01, 72-73. They contend that these sales will be greater than BPA has projected. Sales projections can vary significantly from actual sales because of marketing strategies, water conditions, and other factors that can vary from year to year. The level of water flow during OY 1983 is better than average. Firm loads also are down substantially from projections. These factors contribute to the substantial EB sales during FY 1983. The rate period revenue projections are based on average water conditions, and the assumption that utilities with thermal resources will use their own unsold nonfirm energy to displace their thermal resources before purchasing nonfirm energy from BPA. BPA, E-BPA-4, C-3, C-5. This forecast also assumes that Federal sales of nonfirm energy at the Spill rate are proportional to non-Federal sales. If BPA sales at the Spill rate are less than proportional, this may increase BPA's EB sales. In this event, however, overall BPA revenues would decrease.

The calculation of 3,805 megawatts of Displacement rate sales obviously did not take into consideration either the minimum generation constraints that limit the amount of resource that is displaceable, or the operation cycles of the plants. Before Displacement rate sales can be made it is important to consider both of these factors. In the month of May, only a few thermal resources are available for service at the Displacement rate based on the 11.0 mill/kWh Spill rate outlined in the Evaluation, and revised incremental resource costs from the PNUCC Thermal Resource Database and escalated to midyear OY 1984 and OY 1985 using escalation factors from BPA, E-BPA-7, Attachment 1, 232. These resources are: Colstrip 1 and 2, Colstrip 3 and 4, Corette, and Dave Johnston. When taking into account the minimum generation constraints and the expected generation level in the month of May, a potential market of 421 average megawatts is indicated if the nonfirm Spill rate is in effect. This is substantially less than the 3,805 megawatts figure asserted by the WWPUD's. In the month of June the displacement market is expected to be about 626 megawatts if BPA is selling nonfirm energy at the Spill rate. Some large coal plants are projected to have variable costs that are less than 2 mills above the Standard rate but more than 2 mills above the Spill rate. Therefore, by moving to the Spill rate BPA can reduce the quantity of sales it would expect to make at the Displacement rate.

Decision

Because the record lacks sufficient load forecast information for interruptible sales to customers of NW preference agencies, it is prudent to assume that such sales will not occur. With respect to expected nonfirm sales at the displacement and energy broker rates, BPA is concerned about the ability to extrapolate a single historical year to a projected condition in the rate period. The two conditions noted (different marketing strategies and different water conditions) coupled with the concern about financial integrity dictate that the revenue forecast should not increase expected sales under these two rates.

D. Classification Issues

The classification of costs between capacity and energy is a major issue in the 1983 rate case. BPA classifies costs according to various methods. All are based on the principle of cost causation. BPA acquires resource capability and constructs transmission facilities for different reasons and purposes, so the classification methods used reflect the individual reasons for which costs were incurred. Classification issues arise throughout BPA's rate studies. A brief summary of classification methodologies used in the studies and their sources follow.

1. BPA's load forecast estimates end-use energy loads using an average mills-per-kilowatthour retail rate. Peak loads are computed by applying load factors to the energy forecast.

2. BPA's Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis develops classification percentages based on the resources BPA would most economically acquire to serve incremental energy and capacity loads in the long run. The TDLRIC Analysis also classifies the network and generation-integration segments of incremental transmission investment costs to reflect the fact that these two segments are built to deliver both capacity and energy.

3. BPA's Cost of Service Analysis (COSA) classifies embedded costs on the basis of cost causation according to methods specific to each type of cost. Hydro costs are classified by a formula using average and peaking capabilities of the hydro system under critical water. Fish and wildlife costs are classified according to the overall capacity-energy split of hydro costs. Costs of thermal plants and of resource acquisitions are classified according to the percentages developed in the TDLRIC Analysis. The portion of costs of BPA's conservation programs allocated to rates is classified by a formula using the megawatts of energy and capacity savings valued at the LRIC's of energy and capacity. BPA's other costs of generation, the deferral, and the cash lag adjustment are classified according to the classification of Federal base system (FBS), Exchange, and New Resources (NR) generation annual costs and net repayment requirement. Generation costs of the investor-owned utility (IOU) exchange are classified by a weighted average of FBS and NR classification percentages for generation. Public agency exchange costs are classified by the same percentages as Federal resource costs included in the Priority Firm (PF) rate. The COSA classifies transmission costs 100 percent to capacity.

4. The Wholesale Power Rate Design Study (WPRDS) classifies certain adjustments to the cost allocations from the COSA. Excess revenues, which are credited to rates, are classified according to reverse TDLRIC percentages. The revenue deficiency resulting from BPA's value of reserves credit to the DSI's is classified according to the TDLRIC percentages.

5. The Transmission Rate Design Study (TRDS) uses classification results from the COSA, and classifies all transmission costs to capacity.

The issues relating to classification discussed first are those identified as "generic" in nature; i.e., those that cut across the subject matter of several of BPA's studies. The discussion of those classification issues identified as specific to a given study follows the "generic" discussion.

1. Generic Classification Issues

Issue #1

What is the impact of the classification of costs between capacity and energy on BPA's ability to recover expected revenues?

BPA's Position

The potential impact of classification of costs between capacity and energy on BPA's ability to recover expected revenues was not considered as a separate issue. No analysis of this potential impact was performed for the initial proposal. This issue will be considered as three separate subissues, with a general decision following, covering all subissues.

Subissue #1a

Should BPA attempt to identify "current" costs for classification purposes, and attempt to recover "fixed" costs only via capacity charges, as a possible means of avoiding revenue underrecovery?

Summary of Positions

APAC argued that the potential for revenue underrecovery is increased by attempting to recover fixed costs through energy charges. Shanker, APAC, E-PA-01, 22.

The DSI's argued that the use of anticipated future costs provides signals to customers that lead to reduced usage of energy and underrecovery of current costs. Drazen, DSI, E-DS-07, 12.

The PGP argues that classification of thermal costs in a manner similar to that used for hydro costs would enhance BPA's revenue stability because costs would be allocated based on actual occurrence rather than on a theoretical basis. Garman, et al., PGP, E-PG-01, 32-33.

Evaluation of Positions

The DSI's argued that the record of revenues from past rate cases alone shows that classifying relatively more costs to energy has led to a greater risk of underrecovery, because allocating more costs to energy makes the DSI rate noncompetitive, depressing sales of both energy and capacity to the DSI's. However, no further evidence was available. Drazen, DSI, TR 6326-6327; Drazen, DSI, TR 6330-6331. The witness for APAC also was not able to provide direct evidence that the rate designs since 1979 have harmed revenue stability. Shanker, APAC, TR 7460-7461. This argument is thus a hypothesis.

The DSI's argued in their reply brief that the lack of empirical evidence in their testimony is not essential to their argument regarding classification. Reply Brief, DSI, R-DS-01, 34. Their argument must then stand or fall on logic alone. Specifically, they argue that "[e]ither price signals work, in which case they do affect the potential for [revenue] recovery, or they are ineffective, in which case they should be abandoned in favor of more conservative ratemaking." Reply Brief, DSI, R-DS-01, 34. Several comments are necessary regarding this argument. First, it is not at all clear what an "ineffective" price signal might be, unless it is argued that the demand curve facing BPA is perfectly inelastic. Only with perfectly inelastic demand will quantity demanded be independent of price. However, even with perfectly inelastic demand, total revenue will not be invariant with respect to price: the higher the price, with perfectly inelastic demand, the higher the revenue. Therefore, the implicit argument that ineffective price signals do not affect revenues is false. Moreover, it would be unreasonable for BPA to take the extreme position that the demand curve for BPA power is vertical (i.e., perfectly inelastic). BPA's load forecasts assume that customers and consumers respond to price. Hoffard, BPA, TR 3897-3898; Roberts, BPA, TR 3893.

The second point is that price signals must "work" in some sense; that is, consumers pick certain quantities of electricity because of the price of electricity relative to the prices of other goods. Any price, therefore, sends a signal to consumers. Even a price of zero sends a signal, namely that the good in question is not at all scarce. Consumers presumably would respond to a new price of zero by consuming more, assuming that the old price was greater than zero, in which case the "signal" has "worked". Any argument that price signals do not work, which may be interpreted to mean "do not affect quantities", must provide evidence that demand is perfectly inelastic. No such evidence has been presented, nor is it reasonable or businesslike to assume in the absence of such evidence that the demand curve facing BPA is perfectly inelastic.

The DSI argument misses the point of BPA's classification. It is not the case that the "only purpose" of the classification is "to discourage the use of energy". Reply Brief, DSI, R-DS-01, 34. The classification percentages that result from the TDLRIC Analysis have the purpose of assessing relative scarcities at the long run margin. BPA, E-BPA-06, 1-3. These relative scarcities imply that the cost of serving an extra kWh at the margin is approximately five times the cost of serving an extra kW at the margin.

The argument was offered by APAC, Shanker, APAC, E-PA-01, 22, the DSI's Drazen, DSI, E-DS-07, 12, and the PGP, Garman, et al., PGP, E-PG-01, 36, that fixed costs should not be recovered by energy charges, because revenue underrecovery is more likely. However, as over 95 percent of BPA's costs must be regarded as fixed, Cook, APAC, E-PA-02, 50-51, the 50/50 classification suggested by the DSI's would still leave substantial "fixed" costs recovered through energy charges.

BPA vulnerability to revenue underrecovery as a result of load underruns exists whether costs are primarily classified to energy or capacity. Customer and availability charges would protect BPA from revenue underrecovery as a result of load underruns, yet the DSI's and PGP oppose such charges. The PGP argument that costs should be allocated based on actual occurrence, Garman, et al., PGP, E-PG-01, 32-33, ignores the fact that almost all of BPA's costs have already "occurred," in the sense that BPA must pay these expenses whether power is sold or not. Both capacity and energy sales have been sources of revenue underrecovery in the recent past. Metcalf, BPA, E-BPA-46R, Attachment 1, Tables 1-2, 5. PP&L stated that the use of a 50/50 classification rule, based on the argument that baseload plants produce both kilowatts and kilowatthours, ignores "the relative cost of these two products and would classify costs by a meaningless rule of thumb." Reply Brief, PP&L, R-PL-01, 31. <u>See also</u> Reply Brief, PP&L, R-PL-01, 33-34, concerning APAC's Opening Brief, B-PA-01, 40-42.

The PGP testimony, E-PG-01, also discusses revenue recovery in the context of classification, arguing that classification should follow "cost occurrence" to improve revenue recovery. Garman, et al., PGP, E-PG-01, 33, 43, 45-48. This "theory of cost occurrence" however ignores the fact that "over 90%" of BPA's costs have already "occurred," and payment must be planned notwithstanding the amount of power actually sold. Garman, et al., PGP, E-PG-01, 36. It is therefore impossible to identify costs that have occurred because of load being placed on BPA, in which case the theory of cost occurrence is of no use in classifying costs.

<u>Subissue #1b</u>

Do short run elasticities affect revenue underrecovery?

<u>Summary of Positions</u>

APAC argued that short-run elasticity effects exacerbate the problem of revenue underrecovery. Shanker, APAC, E-PA-01, 22.

Evaluation of Positions

It is generally accepted that short run elasticities are lower than long run elasticities. This reflects the common sense notion that consumers have more alternatives when they have more time to adjust. In this case, increasing the price is more likely to lead to higher revenues in the short run than in the long run, not vice versa. Thus, APAC's argument concerning short term elasticity effects lacks merit.

Subissue #1c

Are capacity loads and revenues more stable and predictable than energy loads and revenues?

Summary of Positions

BPA introduced evidence in rebuttal that both capacity and energy loads and revenues have been less than forecast, in the recent past. Metcalf, BPA, E-BPA-46R, Attachment 1, Tables 1-2, 5. APAC argues that energy-intensive rates have an adverse effect on revenue stability. Shanker, APAC, E-PA-01, 14; Cook, APAC, E-PA-02, 2; Opening Brief, APAC, B-PA-01, 49-55. The PGP asserts that revenues would be more stable if they were expected to come from capacity charges instead of energy charges. Garman, et al., PGP, E-PG-01, 36; Opening Brief, PGP, B-PG-01, 17-20. The PGP believe that a disproportionate emphasis on the energy charge for revenue collection from the Priority Firm class increases BPA's probability of revenue variances. Garman, et al., PGP, E-PG-01, 42; Opening Brief, PGP, B-PG-01, 20-25. They assert that BPA has not analyzed the effects on revenues of the proposed capacity/energy split. Garman, et al., PGP, E-PG-01, 47. However, they speculate that revenues are "more sensitive" to variations in energy loads than to variations in capacity loads. Garman, et al., PGP, E-PG-01, 48. Thus, they conclude that declines in electricity purchases due to mild weather, a depressed economy, and above-normal water conditions lead to greater revenue shortfalls if rates are energy-intensive. Garman, et al., PGP, E-PG-01, 46.

The WWPUD's argue that BPA's monthly energy revenues for the period 1974-81 were more stable than capacity revenues. In addition, they assert that actual energy loads at BPA (1974-82) were closer to forecast than were peak loads. Hutchison, et al., WWPUD, E-WW-01, 35-36; Opening Brief, WWPUD, B-WW-01, 4-5, 17. Therefore, they argue that weighting cost recovery from the energy component of rates more heavily than from the capacity component should improve BPA's revenue stability. Hutchison, et al., WWPUD, E-WW-01, 36.

Evaluation of Positions

A witness for the PGP disagreed in cross-examination with the statement that rates that currently assign more costs to energy than to capacity are more sensitive to changes in energy loads than to changes in capacity loads. Sunday, PGP, TR 6511. This appears to contradict PGP's initial position (supra). The witness agreed that assigning more costs to capacity than to energy makes revenues more sensitive to capacity load fluctuations, and argued that a 50/50 classification split would be the only way to make revenues equally sensitive to changes in capacity and in energy loads. Sunday, PGP, TR 6512.

An attempt was made during cross examination to determine whether the demand for capacity was more or less sensitive to weather, price, and economic fluctuations than the demand for energy. Witnesses for the PGP argued that for two of their systems (Seattle and Tacoma), the impact of weather, price, and economic activity was greater for energy loads than for capacity loads. Crisson, PGP, TR 6631; Garman, PGP, TR 6632-6633. Also, it was argued that in general the demand for capacity is less price-elastic than the demand for energy. Sunday, PGP, TR 6635. However, witnesses for the DSI's and the OPUC admitted that they had no knowledge of any studies that show that the elasticity of demand for capacity is less than that for energy. Carter, DSI, TR 6683-6684; Oliveira, OPUC, TR 7436; Mizer, DSI, TR 6807. It was finally offered in cross-examination that classification based on customers' relative price elasticities of demand for capacity and energy might help the revenue recovery problem, but might also raise problems of equity. Sunday, PGP, TR 6639.

The only empirical evidence was introduced by the PGP rebuttal testimony, through a paper by J. S. Henderson, "Electric System Load Patterns and Demand Charges", May 1979. Garman, et al., PGP, E-PG-06R, 23-26. This paper examined the demand for electricity based on a sample of industrial firms in 1970. As this sample was a cross-section, it can be argued that the resulting demand pattern yields estimates of long run elasticities. Yet, it was argued by a witness for the DSI's that during the test period of this rate case, consumers' responses to price changes will be dictated by short run, not long run, elasticities. Carter, DSI, TR 6685-6686. The conclusions of this paper are not, therefore, clearly relevant for BPA's rate cases. Furthermore, cross examination of PGP's rebuttal testimony revealed the inappropriateness of concluding that the results of a study for industrial customers apply to utilities that purchase power, since neither commercial nor residential loads were analyzed. Sunday, PGP, TR 8186-8187. Furthermore, the study was based on national data from 1970. Sunday, PGP, TR 8187-8188. Thus, it is extremely difficult to argue that this work should be relied on for current BPA ratemaking in the Northwest.

In rebuttal, a witness for APAC argued that the analysis provided in WWPUD's prefiled testimony was invalid because: (1) it did not look at the difference between forecast loads and actual loads; (2) it did not examine individual customer classes and thus ignored changes in different kinds of demand; and (3) it included nonfirm sales. Kalcic, APAC, E-PA-09R, 2-8. Rebuttal testimony for the DSI's supported the first of these three arguments. Carter, DSI, E-DS-19R, 20. In addition, the PGP argued in rebuttal testimony that the WWPUD's analysis ignores current circumstances, including the shift of costs in BPA rates toward energy since 1981. Garman, et al., PGP, E-PG-06R, 12-13. Further arguments were offered by various parties, without empirical evidence, that classifying fixed costs to energy makes customers insensitive to the magnitude of peak demands, Cook, APAC, E-PA-08R, 27, and that classifying costs primarily to energy "may cause" the surplus to increase and the revenue deficits to continue, Carter, DSI, E-DS-19R, 2. However, it was also argued that shifting costs from energy to capacity could increase BPA's revenue recovery problems. Hutchison, et al., WWPUD, E-WW-02R, 6.

PP&L argued in rebuttal testimony that the percent decline in capacity revenues exceeded the percent decline in energy revenues from 1979 to 1981, which indicates that revenues collected from energy charges were more stable than revenues collected from capacity charges. Sirvaitis, PP&L, E-PL-05R, 5. This witness agreed however during cross-examination of rebuttal that his analysis was not directed to the question of deviations of actual from forecast revenue, but rather to the question of changes in revenue over time. Sirvaitis, PP&L, TR 8827.

The question of sensitivity of energy and capacity loads to variations in the weather also was investigated in cross examination of rebuttal testimony. Witnesses for the PGP offered contradictory descriptions of the weather sensitivity of loads. One witness argued that energy loads are more weather sensitive than capacity loads. Sunday, PGP, TR 8300. Another witness stated that the characteristics of individual utilities will determine whether a single extremely cold day in an otherwise normal January will cause a greater percentage increase in capacity or energy loads. Garman, PGP, TR 8301. The same response was given for a similar question directed to an entire month of colder weather. Garman, PGP, TR 8301. If weather sensitivity is indeed utility-specific, BPA cannot reasonably be expected to design rates based on weather sensitivity.

It was argued in the DSI reply brief that strong evidence was presented in E-DS-07 and E-PG-01 supporting the proposition that actual energy revenues deviate more than actual capacity revenues from their respective expected levels. Reply Brief, DSI, R-DS-01, 35. Arguments in E-PG-01 are discussed immediately below. The relevant section of E-DS-07 appears to be pages 13-15, where Effects of Classification Decisions are discussed, and where it is alleged that BPA's underrecovery of costs has been an inevitable result of BPA's rates. However, nowhere in this document is the possibility seriously discussed that BPA's revenues are a function of many factors, including its rates, the weather, national economic activity, available water, and export market conditions. It is impossible to forecast all these factors with complete accuracy. All of these factors have changed since 1979, and all are different in actuality from their respective forecast levels. It is insufficient merely to note that revenue underrecovery has occurred since introduction of the TDLRIC Analysis, and then to conclude that the underrecovery is caused by the Analysis.

The PGP argue that for a specific five month period, revenues from PGP utilities would have been higher had BPA adopted the PGP proposal on classification. Garman, et al., PGP, E-PG-01, 36. However, five months' data for one group of customers are insufficient evidence for such broad decisions. Furthermore, this conclusion is based on the assumption that loads would not respond to the change in rates. Garman, et al., PGP, E-PG-01, Appendix A, Exhibit 5, 5. As the PGP proposal includes a 33.5 percent increase in the PF winter capacity rate, a 14.7 percent decrease in the PF winter energy rate, a 19.0 percent increase in the PF summer capacity rate and a 14.3 percent decrease in the PF summer energy rate, this assumption of perfectly inelastic loads is clearly unreasonable. Garman, et al., PGP, E-PG-01, Appendix A, Exhibit 5, 5.

Decision

The PGP witnesses argued that BPA's revenue deficiency "has been due largely" to BPA's costing approach, namely classification. However, they fail to quantify "largely", and they provide no evidence that would help BPA discriminate among all the potential causes for revenue underrecovery. The simple statement that "x causes y" is not proof that "x causes y," especially where alternative, reasonable, causal factors are readily available. BPA presented evidence in rebuttal regarding revenue recovery. Metcalf, BPA, E-BPA-46R, 5-8 and Attachment 1, Tables 1 and 2. This evidence strongly suggested that displacement by generating public utilities with available nonfirm hydro power has been a serious cause of revenue underrecovery, one not likely to be offset by cost allocation. No contradictory evidence was presented by any parties that questions the accuracy or validity of this analysis, nor has this analysis been questioned in either opening or reply briefs.

It must be recognized that both capacity and energy yield "variable" revenues. Neither is a fixed quantity, to be counted on for revenues under all circumstances. The ICP argued that a more capacity-intensive classification would increase the risk that BPA will be driven from the capacity market. Sirvaitis, ICP, E-IC-04, 7-8. It would be clearly imprudent to rely on either capacity or energy as certain sources of revenues. This was acknowledged by the DSI's. Ater, DSI, TR 9099.

It is difficult to accept arguments that BPA should classify more but not all of its fixed costs to capacity, because no reasoning has been offered that reconciles the conflict between "fixed/variable" and the 50/50 rule. Recovering fixed costs entirely via capacity charges would result in approximately 95 percent of BPA's costs allocated to capacity, which would leave BPA seriously vulnerable to load underruns in capacity, and would expose BPA to serious substitution away from its capacity.

Thus, no clear relationship has been established between classification and expected recovery of needed revenues. It is possible that energy loads are no more or less sensitive to changes in weather, rates and general economic activity than are capacity loads. This uncertainty was admitted by the DSI's. Ater, DSI, TR 9099. No clear and strong empirical evidence supports the PGP, APAC, and DSI positions that energy revenues are "more unstable" than capacity revenues. It is clear however that low load factor customers favor energy-intensive classification, and high load factor customers favor capacity-intensive classification, because in each case the favored method leads to lower total bills for the party in question, and ipso facto higher total bills for all other parties. BPA must make classification decisions on grounds other than these.

As the WWPUD's point out in their reply brief, "[t]o cite the fact that Bonneville has experienced an underrecovery problem, and then assert, without substantiating evidence, that one aspect of the rate setting process is entirely responsible for it is hardly persuasive." Reply Brief, WWPUD, R-WW-01, 12. Many factors may contribute to revenue instability, most of which are beyond BPA's control. Weather and the general economic climate clearly are not functions of BPA rates. BPA believes that revenue underrecovery is a serious problem, and continues to analyze the specific sources and causes. BPA, therefore, has decided that classifying more costs to capacity than in the initial proposal will not necessarily enhance revenue stability or recovery, and may contribute to greater revenue instability. Without more objective evidence, it would be imprudent to assume that classifying more costs to capacity will enhance revenue stability.

Issue #2

Will BPA's proposed rate design cause erosion of BPA's system load factor?

Summary of Positions

APAC argued in their prefiled testimony that changes in BPA's rate design have caused an "erosion" of system load factor. Cook, APAC, E-PA-02, 40. They stated that it is inappropriate to classify fixed production costs to energy because it encourages a particular class to decrease its load factor relative to the system's load factor. Cook, APAC, E-PA-08R, 24-27. "An energy classification of production fixed costs renders customers insensitive to the magnitude of their peak demands." Cook, APAC, E-PA-08R, 27.

The PGP agreed with APAC that the net effect of raising energy rates relative to capacity rates is to lower the system load factor. Seattle City Light has been cited as an example of this phenonemon. Garman, PGP, TR 6635. The PGP noted that setting rates as a function of load factor might mitigate BPA's revenue recovery problems, but that such a rate structure could also cause equity problems. Sunday, PGP, TR 6639.

PP&L took issue with APAC and PGP, claiming that APAC's analysis was "worthless, as it did not distinguish between nonfirm loads, which BPA can schedule at will, and firm loads, which are the relevant loads for consideration." Opening Brief, PP&L, B-PL-01, 24. Furthermore, PP&L pointed out that PGP's own testimony included a study which "concluded that increases in energy prices relative to demand prices actually may improve customer load factors." Sunday, PGP, TR 8191; Opening Brief, PP&L, B-PL-01, 24.

Evaluation of Positions

Despite APAC's contention that BPA's system load factor has been declining over time, APAC's own data show otherwise. Shanker, APAC, E-PA-01, Attachment RJS-4. While it is true that in the first two years of the study (1975 and 1976) the system load factor was in the 70 percent range, since that time the load factor has fluctuated between the high 50's and high 60's. However, one of the years with the lowest load factor (59.6 percent) was 1977, when the same rates were in effect that "produced" much higher load factors in earlier years. Under cross-examination, Mr. Shanker agreed that in 1979 (when BPA's first rate increase since 1974 went into effect) BPA's load factor was 62.2 percent, but that in 1983 it had risen to 63.3 percent. Shanker, APAC, TR 7455. APAC agrees that the timing and amount of nonfirm energy sales affect system load factor. Shanker, APAC, TR 7455-7458. Consequently, it would be inappropriate to conclude that BPA's load factor is steadily declining or that the load factor is related to the relative magnitude of BPA's energy and capacity rates in any systematic way. Since sales of nonfirm energy are heavily dependent on the availability of water, which cannot be predicted with any accuracy, it would be better to consider only firm loads.

The argument that the net effect of raising energy rates relative to capacity rates is to lower the system load factor is, nonetheless, worthy of consideration. As capacity becomes relatively inexpensive there may be less incentive to restrain capacity growth than energy growth. However, although high load factors traditionally are considered "good," BPA's rates are not designed specifically to achieve a high load factor; rather, they are designed to convey to the customers a sense of the relative marginal costs of capacity and energy, to recover BPA's revenue requirement, and to meet other goals.

In its reply brief, APAC argued that BPA "does not dispute that energy intensive rates have a tendency to lower load factor." Reply Brief, APAC, R-PA-01, 17. APAC also states that "[i]t is clear that the 'load factor is related to BPA's rates in a [sic] systematic way.' See Evaluation at 37." Reply Brief, APAC, R-PA-01, 19. The first statement is false, and represents a misreading of pages 36-37 of the Evaluation of the Record. The second statement reverses through ellipsis and misquotation the clear intent of the original complete sentence: "Consequently, it would be inappropriate to conclude that BPA's load factor is steadily declining or that the load factor is related to BPA's rates in any systematic way." Evaluation of the Record, A-01, 37. As noted above, annual load factor statistics presented by APAC's own witness indicate that load factor may both increase and decrease while rates remain constant, and that load factors in 1979 and 1983 were greater than in some of the years before the TDLRIC Analysis was implemented. This is not evidence that rates are related to load factor, and cannot be used to make adjustments to the rates with any confidence that alleged results will occur. The only possible conclusion at this point is that not enough is known about the possible impact of rates on system load factor. Adjustments to rates intended to achieve specific load factors would be extremely speculative.

Decision

The parties have not demonstrated to BPA's satisfaction that there has been, over the past ten or so years, either a systematic "erosion" of BPA's system load factor or any clear connection between rates and load factors. Furthermore, they have not shown that adoption of the initial proposal will result in further such "erosion". Given the evidence on the record, it is possible that classifying more costs to capacity will lead to a lower load factor. Thus, neither changing the proposed classification for that reason nor adopting load-factor-based rates would be prudent given the data on the Record.

Issue #3

Is the overall classification of costs between capacity and energy in the Priority Firm (PF) rate appropriate?

Summary of Positions

In the supplemental testimony 35 percent of the PF costs were classified to capacity and the remaining 65 percent were classified to energy. Metcalf, BPA, E-BPA-32S, Attachment 1, 6. This classification reflects the results of the COSA, the various rate design adjustments, and the equalization of demand. BPA believes that the initial proposal as supplemented reflects appropriate classification procedures and will result in recovery of BPA's revenue requirement.

APAC argued that because most of BPA's costs are fixed, it would be appropriate to classify relatively more costs to capacity. Cook, APAC, E-PA-02, 51-52. According to APAC, the PF rate design should be brought more in line with cost causation by reducing BPA's "artificially inflated" energy charges. Cook, APAC, E-PA-02, 49.

Evaluation of Positions

Parties have attributed many effects to BPA's PF rate design. The rate design has been treated as being responsible for computed requirements customers' displacement of BPA purchases and for an "erosion" of the Federal system load factor. However, although some parties believe that BPA's rate design decreases energy use, the highest level of energy consumption for the years listed in APAC's testimony (1975-1982) occurred in 1982. Shanker, APAC, E-PA-01, Attachment RJS-4; Shanker, APAC, TR 7465. Thus, it has not been demonstrated that BPA's PF classification has any effect on levels of firm energy consumption.

Under cross-examination, BPA's witness observed that BPA is attempting to "reflect in our rates the relative incremental cost of energy and capacity and we recognize that that may well have an influence upon the behavior patterns of the customers. We're not trying to elicit any particular response from them, other than that they behave in an economic manner." Metcalf, BPA, TR 7318. It would not be appropriate to use the perceived results of BPA's classification to select classification percentages; rather, the classification should accurately reflect BPA's costs and the various goals served by BPA's rates.

The WWPUD's take issue with contentions regarding BPA's proposed classification for the PF rate. The fact that most of BPA's costs are fixed does not mean that they necessarily are capacity related, according the WWPUD's. Such an assertion "ignores the reasons for which those costs were incurred" and would adversely affect BPA's revenue recovery. Hutchison, et al., WWPUD, E-WW-02R, 19. The use of the TDLRIC Analysis classification percentages for WNP-1, -2 and -3 reflects the fact that these plants were planned and built to supply perceived energy needs of the region. Opening Brief, WWPUD, B-WW-01, 34.

APAC observed that while BPA is following the basic mandate of the Northwest Power Planning Council, the Council has recommended a certain temperance with respect to implementation of its recommendations. In its Draft Plan, the Council concluded that "[r]educed customer charges and demand charges, increased energy rates, and particularly marginal energy rates, inverted rates, are appropriate rate designs. . . . The aggressiveness with which these rate designs should be implemented will depend on the duration and saleability of the current firm surplus and the revenue problems attendant on the surplus." Shanker, APAC, TR 7452-7453. This comment simply implies that the Council believes BPA should consider current circumstances in setting rates. However, APAC's position that BPA should use a classification method that would dramatically shift BPA's rate design toward capacity charges would be completely contrary to the direction urged by the Council.

According to APAC, one way to factor BPA's cost causation into the rate design would be to set energy charges half way between "unit costs" and the present energy charges. Cook, APAC, E-PA-02, 62-63. However, this solution is purely arbitrary and the impact on revenue recovery is speculative and ambiguous. According to APAC, current "short term sales send conflicting and confusing price signals to consumers." Shanker, APAC, TR 7461-7463. This confusion is allegedly rooted in the fact that BPA's firm power is priced at an "energy-intensive" rate while the short-term sales, presumably to DSI customers, are priced at very low marginal energy rates. However, in cross-examination, APAC agreed that it is not difficult to determine that these sales are short term given a termination date of October 31, 1983, and a contract entitled "Interim Sale." Shanker, APAC, TR 7461-7463. Thus, DSI customers are sent the price signals that certain energy may be less expensive in the short run than in the long run. The signals are thus clearly allied to specific time periods.

Further, APAC commented that FERC recently has been endorsing capacity-intensive rates. Shanker, APAC, E-PA-01, 21; Cook, APAC, E-PA-02, 51-52. However, FERC approved BPA's 1979 rates, which were in part based on the use of "energy-intensive" LRIC classification results.

Decision

The Northwest Power Planning Council has recommended a greater emphasis on energy charges in setting rates. Emery, BPA, TR 4901. Witness for the WWPUD's argued that the hydro system is energy-dominated, and that the cost of producing energy is escalating more rapidly than that of capacity. Saleba, WWPUD, TR 6399, 6400. This supports results that are more weighted toward energy than capacity. The fact that proposed capacity charges are higher relative to the LRIC of capacity than are proposed energy charges to the LRIC of energy implies that consumers are being given a clear signal to economize on capacity rather than energy. Sirvaitis, PP&L, TR 7642, 7643, 7648.

BPA continues to classify PF costs as it did in the initial proposal. The classification in the initial proposal reflects a combination of the costs associated with the FBS (mostly hydro) and BPA's LRIC of thermal resources. By classifying relatively more costs to energy, BPA may lose energy sales, but by classifying more costs to capacity, capacity sales may be lost. The Northwest Power Planning Council's Draft Plan supports BPA discretion in this matter, and support classifying more costs to energy, and less to capacity.

Issue #4

Are BPA's customer and availability charges inconsistent with BPA's classification based on TDLRIC results?

Summary of Positions

BPA proposed using the relative LRIC of capacity and energy as developed in the TDLRIC Analysis to classify costs of thermal resources, resource acquisitions, and the revenue deficiency resulting from BPA's value of reserves credit to the DSI's. Also, excess revenues are classified according to reverse TDLRIC percentages. This classification sends signals to customers regarding the relative scarcity of capacity and energy in the long run, thus encouraging more efficient consumption and investment decisions. BPA, E-BPA-05, Appendix D, D-5; BPA, E-BPA-07, 14; BPA, E-BPA-06, 1-3. BPA also proposed an "availability charge" for computed requirements customers and a "customer charge" for DSI customers, to mitigate revenue recovery problems experienced with these two customer groups. BPA, E-BPA-07, 28-32.

APAC argued that fixed charges conflict with and are opposite to TDLRIC price-signal goals. Shanker, APAC, E-PA-01, 15, 23. Such charges, it was argued, set the marginal cost of the first 50 percent of a generating customer's energy purchases equal to zero. Shanker, APAC, E-PA-01, 15. It was also argued that forcing customers to pay for unused energy is "illogical and contradictory." Shanker, APAC, E-PA-01, 23. It was stated that there is little sense in sending price signals that energy is scarce and then penalizing customers for heeding those signals. Opening Brief, APAC, B-PA-01, 92; Garten, APAC, TR 9126. APAC also argued that if the implementation of less energy-intensive rates did not solve revenue underrecovery problems, a customer charge should be implemented. Cook, APAC, E-PA-02, 49; Opening Brief, APAC, B-PA-01, 91. APAC suggested that as an alternative, a customer charge for generating utilities be considered that would recover a portion of the cost of displaced energy. Cook, APAC, E-PA-02, 50.

The PGP argued that an availability charge encourages maximizing energy purchases from BPA. Garman, et al., PGP, E-PG-01, 18-19. They argued that the proposed PF rate, incorporating the availability charge and the classification of some resources according to TDLRIC results, is contradictory and internally inconsistent. Garman, et al., PGP, E-PG-01, 19, 49. They described BPA's proposed solution to revenue underrecovery as "ad-hoc" and a "band-aid". Garman, et al., PGP, E-PG-01, 20. They argued that BPA is thereby signaling PGP utilities to change operations, not to use resources efficiently, not to conserve energy, and to use non-BPA resources. Garman, et al., PGP, E-PG-01, 13-14; Opening Brief, PGP, B-PG-01, 14. The PGP also argued that BPA sends an energy-intensive price signal, and then penalizes customers for following that signal. Opening Brief, PGP, R-PG-01, 7, 8.

The DSI's argued that a fixed charge is inconsistent with energy-intensive rates. Ater, DSI, TR 9102. They also argued that customer and availability charges demonstrate a lack of faith in price signals. Reply Brief, DSI, R-DS-01, 55-56. They argued further that it is schizophrenic to send price signals and then to countermand those signals with take-or-pay provisions. Reply Brief, DSI, R-DS-01, 55.

The NWU's argued that the purpose of a customer charge is to provide certainty. Opening Brief, NWU, B-NW-01, 59-60. They also argued that any customer charge should be designed to protect revenues in the event of an economic recession. Opening Brief, NWU, B-NW-01, 59.

Evaluation of Positions

The argument by the PGP and APAC that BPA is sending an energy-intensive price signal and then penalizing customers for following that signal ignores the important differences among the purposes of various charges. The results of the TDLRIC Analysis provide the relative prices of energy and capacity in the long run. BPA, E-BPA-06, 1-3. BPA does not attempt to charge rates equal to LRIC, but rather to maintain signals regarding relative prices. Emery, BPA, TR 4793. Other important goals are revenue recovery and stability. BPA, E-BPA-07, 1-2. BPA can maintain the relative price signals concerning capacity and energy while collecting some revenue through more fixed charges, thus improving revenue recovery and stability. It is still the case that reductions in consumption of capacity and energy are rewarded according to the relative prices of those two goods, and that customers know by the price signals that energy is expensive relative to capacity.

APAC argued that the imposition of fixed charges contradicts price signals, but also argued that customer charges could help solve revenue recovery problems. They suggested that more capacity-intensive rates should first be implemented, and then customer charges set only if revenue recovery problems persist. Cook, APAC, E-PA-02, 49-50; Opening Brief, APAC, B-PA-01, 91. However, given the evidence on the record, evaluated above under Issue #1c, such a course of action would be imprudent, and would expose BPA to continued problems of underrecovery.

Customer charges have the effect of providing increased certainty of revenues earned. Opening Brief, NWU, B-NW-01, 59-60. As BPA has experienced revenue underrecovery in the past, implementing measures that can provide such certainty is prudent.

Decision

BPA's customer and availability charges serve purposes distinct from the purposes served by the classification of costs. Customer and availability charges help achieve the goal of revenue recovery, while classification serves the purpose of identifying relative prices of capacity and energy. All these goals are standard elements of ratemaking. Therefore, BPA concludes that its customer and availability charges are not inconsistent with its classification.

2. Load Forecast Issues

Issue #1

Should BPA's forecast of non- and small-generating public utility loads incorporate retail rate classification methods?

Summary of Positions

BPA's forecast of non- and small-generating public utility loads is based on economic conditions, average retail electricity price, and weather. BPA, E-BPA-03, 15-19. The average price includes both capacity and energy components and is based on the average retail electricity costs utilities must recover from revenues. The forecast does not reflect retail rate classification methods, nor does it reflect end-use rate impacts on particular consumer groups. Hoffard, BPA, TR 3888-3905.

APAC suggested that BPA's forecast of non- and small-generating public utility loads does not reflect the impacts of wholesale classification on retail rate design and in turn does not reflect effects of retail classification on end-use consumer loads. The forecast does not discriminate between energy and capacity charges, but rather uses an average of them. Garten, APAC, TR 3904-3905; Opening Brief, APAC, B-PA-01, 22-24.

Evaluation of Positions

APAC argued that BPA's forecast of non- and small-generating public utility loads should incorporate retail rate classifications, stating that if the impacts of rate design on ultimate consumers are not incorporated, the forecast may not be reliable and may cause problems in BPA's revenue projections and cost allocation.

BPA acknowledges that a load forecast that incorporates the effects of retail classification could prove valuable. However, BPA is uncertain whether such a retail rate analysis would have a substantial enough impact on the load forecast to merit such a complex study. Hoffard, BPA, TR 3904. If undertaken, a separate analysis would be necessary for each of the approximately 109 utilities to which BPA markets power. Hoffard, BPA, E-BPA-11; Taves, BPA, TR 3716. Furthermore, BPA has no control over the retail classifications or rate designs of these utilities, and thus BPA has no assurance that retail rates will reflect price signals provided in BPA wholesale rates. Accordingly, the forecast of non- and small-generating public utility loads was based on how the energy and capacity components of BPA's wholesale rates affect each utility's average retail price of electricity. These average prices reflect the total costs utilities need to recover from revenues and can be recovered by any number of different rate designs. Taves, BPA, TR 3714-3716.

Decision

Given that a utility can institute a large number of rate designs and retail classifications in order to recover total costs, and given that retail rate design is primarily a retail utility responsibility, BPA believes that its present forecasting methodology, using an average retail electricity price, is adequate. Additionally, since it is difficult to analyze retail rate designs resulting from wholesale rate design and because BPA is not certain that such an analysis would have much of an impact on the load forecast, BPA has not revised its forecast of non- and small-generating public utility loads.

3. COSA Issues

a. Methodologies

Issue #1

Should BPA use a single method to classify all generation costs between capacity and energy?

Summary of Positions

BPA uses different methods to classify costs related to generation. Each of the methods is based on the principle of cost causation. Carr & Revitch, BPA, E-BPA-28, 11-12; BPA, BPA-5, Appendix D, D-1.

The ICP proposes that BPA classify all generation costs on the basis of the classification percentages developed in BPA's Time-Differentiated Long Run

Incremental Cost (TDLRIC) Analysis. The ICP argues that BPA's TDLRIC classification results send a price signal to customers that accurately reflects the relative incremental costs of capacity and energy. Sirvaitis, ICP, E-IC-04, 8-9; Opening Brief, PP&L, B-PL-01, 21-23. Thus, they assert that BPA's revenues would have been more stable and closer to forecast levels if more costs had been classified to energy. Sirvaitis, PP&L, E-PL-05R, 4-5; Opening Brief, PP&L, B-PL-01, 23. PP&L believes that use of TDLRIC pricing would assist in the efficient allocation of resources and pricing of power. Reply Brief, PP&L, R-PL-01, 1.

The DSI's suggest that BPA adopt a single classification technique for all generation costs in the COSA. Carter, DSI, E-DS-09, 1. The results of such a single method would be an approximately equal classification of costs between energy and capacity. Carter, DSI, E-DS-09, 5.

The PGP claims that BPA's methods are inconsistent, make rational planning by BPA's customers extremely difficult, and contribute to BPA's persistent underrecovery of revenues. Garman, et al., PGP, E-PG-01, 28-29. The PGP also suggests an equal classification of generation costs to capacity and energy as a reasonable proxy for the results of BPA's several methods. Opening Brief, PGP, B-PG-01, 18.

Evaluation of Positions

BPA incurs generation costs for a variety of different resources and programs, such as hydro generation, thermal generation, exchange power, conservation programs, resource acquisitions, and others. Because costs related to these programs and resources are incurred for different reasons, BPA classifies these individual costs by methods that reflect the various causes underlying their construction and operation. BPA, E-BPA-05, 17; Carr, BPA, TR 5047-5050.

ICP testimony, in defense of using TDLRIC percentages to classify all costs, asserts that BPA's rates signal customers to economize on capacity relative to energy consumption over the short run, and encourage utilities to construct capacity resources in the long run. The ICP argues that BPA may price itself out of the capacity market. Sirvaitis, ICP, TR 9046; Sirvaitis, ICP, E-IC-04, 8. BPA agrees that price signals sent to customers are an important result of choosing a classification methodology. Metcalf, BPA, TR 7318. However, price signals are primarily a rate design issue. BPA's COSA, in contrast, considers the causes underlying expenditures related to the products and services provided by the generation and transmission systems. BPA, E-BPA-05, 2. The methods of classification of generation costs used in the COSA are all based on the principle of cost causation. The various methods reflect the causes for construction and operation of the various generation resources. BPA, E-BPA-05, Appendix D, D-1.

The DSI's argument for use of a single method to classify generation costs rests on the assertion that BPA's current methods create complications and lead to inequities. They claim that a single classification method would make the COSA easier to understand and reduce the level of controversy about classification. Carter, DSI, E-DS-09, 3. The DSI's state that any classification percentages "within a reasonable range", used consistently, will produce a fair allocation of costs over time. Carter, DSI, E-DS-09, 4-5. BPA's classification methods can be considered complicated, but simplification could lead to inaccuracy. The DSI's argument does not discuss the inequities it claims are the result of BPA's classification methods, nor does it define a "fair" allocation of costs. "A reasonable range", defined as approximately a 50/50 split between demand and energy, is unsupported by classification theory or empirical study in the DSI's testimony.

The PGP proposes that BPA use a formula similar to its classification formula for hydro costs to classify thermal costs. Garman, et al., PGP, E-PG-01, 32. This would apparently satisfy the PGP's desire to classify all generation costs using a single method. The formula will be discussed in the section of this document dealing with classification of thermal generation costs. The suggestion of the PGP in its opening brief to round the variety of classification splits proposed by parties to the rate case to 50/50 is arbitrary. Opening Brief, PGP, B-PG-01, 18. The PGP provides no theoretical or empirical evidence to support its claims that such a classification would not penalize one customer group at the expense of another, nor that the results would not arbitrarily be skewed. They also fail to support their assertion that BPA's classification methods interfere with rational planning by customers. Revenue underrecovery has been addressed in previous sections of this document.

Decision

BPA does not believe that it is appropriate to classify all of its generation costs by a single method, for simplicity or to achieve a predetermined result. BPA prepares a Cost of Service Analysis to assign costs of its system to those who use the system. BPA has developed various classification methods for its various costs, to reflect their causation. Therefore, BPA does not accept the recommendation to classify its costs using a single method.

b. Classification of Hydro Resource Costs

Issue #1

Is BPA's method for classifying hydro resource costs appropriate?

Summary of Positions

BPA classifies hydro resource costs according to a method which reflects principles of cost causation. BPA identified all hydro generation resources installed solely to provide peaking capacity and classified those costs 100 percent to capacity. All other units are considered to be a part of the base hydro system. BPA identified the peaking capability of these base hydro units (14087 MW) and the critical energy capability of these units at

100 percent plant factor under critical water conditions (7576 MW). The critical energy capability available at 100 percent plant factor also provides an equal amount of capacity, so BPA's formula classifies this capability equally to capacity and energy. All remaining megawatts up to the peaking capability of these units provide only capacity, so they are classified entirely to capacity. This method results in the classification of base hydro system costs 27 percent to energy and 73 percent to capacity. BPA, E-BPA-05, Appendix D, D-2; Carr & Revitch, BPA, E-BPA-28, 11.

The ICP argues that because streamflows are not even over the critical period, more than 7576 megawatts of capacity are required to generate 7576 average megawatts of energy. They argue that in order to avoid spill of firm energy from heavy runoff or rainfall during the critical period, sufficient capacity must be installed to handle flows that cannot be stored. They argue that the costs of baseload hydro capacity that was installed to avoid spill under critical water should be classified to energy. Sirvaitis, ICP, E-IC-04, 10; Opening Brief, PP&L, B-PL-01, 21-23; Reply Brief, PP&L, R-PL-01, 3.

The WWPUD's argue that baseload hydro costs should be classified on the basis of costs of replacement resources with similar capabilities, using BPA's LRIC's of capacity and energy. Hutchison et al., WWPUD, E-WW-01, 23; Opening Brief, WWPUD, B-WW-01, 40; Reply Brief, WWPUD, R-WW-01, 13-14.

The OPUC recommends using results from its LP model, based on average water conditions, to classify hydro costs. Oliveira, OPUC, E-OP-01, 33.

APAC recommends that baseload hydro costs be classified using the NARUC method. This method assigns the cost of megawatts generated to meet firm load requirements under critical water conditions to capacity. The cost of the remaining resources, up to the output under average water conditions, is assigned to energy. Cook, APAC, E-PA-08R, 4; Opening Brief, APAC, B-PA-01, 62.

The DSI's support BPA's hydro classification. Opening Brief, DSI, B-DS-01, 45.

Evaluation of Positions

The ICP argues that the base hydro system must have more than 7576 megawatts of capacity to capture 7576 average megawatts of energy under critical water conditions. They argue that the costs of all capacity required to avoid spill of firm energy during the critical period should be classified to energy. They propose that a reasonable estimate of this energy-related capability would be the highest average rate at which each plant ran for a month during the critical period. Sirvaitis, ICP, E-ICP-04, 10-11. APAC points out that the amount of power produced by the baseload units depends on three factors: (1) the amount of water available; (2) the head; and (3) the demand for electric power. If demand were not variable, critical water at 100 percent plant factor would produce 7576 average megawatts of energy. Cook, APAC, E-PA-08R, 8. APAC asserts that baseload plant in addition to what is needed to capture all critical energy is required to meet this changing demand, so should be classified to demand. Cook, APAC, E-PA-08R, 9. The DSI's point out that this additional plant is installed not only to avoid spill, as the ICP claims, but also to meet and shape for loads, and to allow thermal maintenance. Carter, DSI, E-DS-19R, 13-14. The ICP analysis fails to show which of these functions is being performed when hydro production is highest, so the ICP cannot reasonably claim that all or part of costs of hydro plant in addition to that used under critical water should be classified to energy. Carter, DSI, E-DS-19R, 13-14.

The WWPUD's replacement method is based on the rationale that, if BPA had to replace the baseload hydro facilities, 7576 average megawatts of energy and 14087 megawatts of capacity would have to be purchased from current least cost resource options. They state that results of BPA's TDLRIC Analysis are proper pricing surrogates for this replacement demand and energy. Hutchison et al., WWPUD, E-WW-01, 23-24; Opening Brief, WWPUD, B-WW-01, 41. However, as APAC states in its rebuttal testimony, BPA clearly does not need to replace the base hydro system now, and probably will not replace it in the foreseeable future. Cook, APAC, E-PA-08R, 7. The WWPUD's method is meant to represent the contribution of the hydro facilities to the region's power supply requirements. Hutchison, et al., WWPUD, E-WW-01, 22; Opening Brief, WWPUD, B-WW-01, 40. As pointed out in the DSI's Opening Brief and by BPA witnesses, however, the Federal hydro facilities perform a load following function which is capacity related. Opening Brief, DSI, B-DS-01, 44; Carr, BPA, TR 5176-5177. Classifying a majority of costs to energy would not recognize the contribution of the hydro system to capacity production.

OPUC recommends using classification percentages derived from their LP models. However, their recommended percentages do not incorporate the results of models which assume critical water conditions. Oliveira, OPUC, E-OP-01, 31. The OPUC believes that rates should not be based on unlikely future conditions such as critical water. Oliveira, OPUC, E-OP-01, 31-32. Under BPA's planning criteria, however, BPA acquires resources sufficient to meet firm loads under critical water conditions. BPA, E-BPA-05, 7; BPA, E-BPA-06, 24. OPUC's recommended method fails to take into account the results of studies that contain assumptions reflecting BPA's planning criteria, and thus are not consistent with the principle of cost causation.

APAC states that BPA's method of classifying baseload hydro costs is based on BPA's system planning criteria, not on operational characteristics. They state that the NARUC method of classifying hydro costs is better supported by operational reality. Cook, APAC, E-PA-08R, 5. The NARUC method compares energy available under average water conditions with energy available under critical water conditions. Cook, APAC, E-PA-08R, 6. BPA's hydro resource planning is based on the goal of having sufficient capacity to meet all firm loads under critical water conditions. Consequently, both capacity and energy loads must be met with available resources under critical water conditions. BPA, E-BPA-05, Appendix D, D-2. The NARUC classification method, although it yields results similar to those from BPA's cost-causation-based method, is inconsistent with BPA's planning assumptions. A witness for APAC pointed out that the NARUC method would be appropriate if operating reality were BPA's primary criterion for choosing a hydro cost classification method. Cook, APAC, E-PA-08R, 6. Later, APAC recommended that BPA retain its current hydro classification method. Opening Brief, APAC, B-PA-01, 62. BPA's hydro classification method, unlike APAC's original suggested method, is consistent with both BPA's primary planning criterion of critical water and the operating characteristics of the Federal hydro system.

Decision

BPA's current method for classifying costs of baseload hydro facilities reflects cost causation through an examination of the operational characteristics of the Federal hydro system. It also reflects BPA's resource planning criteria. BPA believes that this method is theoretically sound, and accurately reflects the relative costs of capacity and energy provided by the Federal hydro system. Therefore, BPA continues to classify baseload hydro costs using its present method.

c. Classification of Thermal Generation Costs

Issue #1

By what method should BPA classify thermal generation costs?

Summary of Positions

BPA classifies thermal costs based on results from its TDLRIC Analysis. The TDLRIC Analysis reflects BPA's assumption that thermal plants are being built primarily to supply energy, but also will provide capacity. BPA, E-BPA-05, 17; BPA, E-BPA-05, Appendix D, D-3; BPA, E-BPA-06, 6-7.

APAC recommends using the fixed-variable method to classify thermal costs, which would classify a majority of thermal costs to capacity. APAC states that this method reflects true cost causation and operating characteristics. Cook, APAC, E-PA-02, 23. APAC presented extensive testimony arguing that Northwest thermal plants are being constructed to provide capacity, and that the region is demand-constrained. Cook, APAC, E-PA-02, 26-39.

The PGP recommends that BPA classify its thermal costs using an approach similar to that for hydro costs. A percentage of costs equal to half a thermal plant's plant factor would be classified to capacity, with the remainder of costs classified to energy. Garman et al., PGP, E-PG-01, 32; Opening Brief, PGP, B-PG-01, 21.

The WWPUD's argued that the Supply System plants were built to meet perceived energy needs, and thus should be classified according to the results of the TDLRIC Analysis. Opening Brief, WWPUD, B-WW-01, 34. Thus, the WWPUD's support BPA's use of TDLRIC Analysis results to classify thermal costs. Reply Brief, WWPUD, R-WW-01, 14.

The ICP also supports TDLRIC classification. Sirvaitis, ICP, E-IC-04, 8; Opening Brief, PP&L, B-PL-01, 21.

Evaluation of Positions

APAC states that the fixed/variable classification method, in which fixed costs are classified to capacity and variable costs to energy, reflects true cost causation and generation operating characteristics. They state that this method reflects the fact that generation resources in the Pacific Northwest are being built to supply both additional capacity and energy. Cook, APAC, E-PA-02, 24; Opening Brief, APAC, B-PA-01, 61. Although extensive historical evidence was presented to show that thermal plants were supposedly constructed to provide capacity, no link was ever made to the fixed-variable method. Cook, APAC, E-PA-02, 23-46. The fixed-variable method is particularly ill-suited to a hydro system such as BPA operates, because it is energy constrained. Reply Brief, WWPUD, R-WW-01, 15. BPA analysis indicates that in the long run BPA is energy deficit under critical water. BPA is acquiring thermal plants primarily to serve this energy deficit, as pointed out by the WWPUD's, and use of classification percentages developed in the TDLRIC Analysis reflects this reason for incurring thermal plant costs. Opening Brief, WWPUD, B-WW-01, 16-17; Reply Brief, WWPUD, R-WW-01, 15. The TDLRIC percentages also reflect thermal plants' secondary product, capacity. BPA, E-BPA-06, 14.

Under the PGP method, 50 percent of the thermal costs up to the plant's plant factor would be classified to capacity. All remaining costs would be classified to energy. Garman et al., PGP, E-PG-01, 32. They claim that this method's advantages include consistency in classifying generation costs, and ease of understanding and application. They also claim that it is based on cost causation, and would add to BPA's revenue stability since costs would be allocated based on actual occurrence. Garman et al., PGP, E-PG-01, 33. Cross-examination of the PGP showed that the PGP method classifies a larger percentage of costs to capacity the higher the plant's capacity factor, a clear anomaly. Reply Brief, WWPUD, R-WW-01, 16; Knitter, PGP, TR 6503-6506. None of the reasons cited by the PGP for using its formula conform to BPA's criterion of cost causation as a basis for classification. Even its example does not clearly demonstrate how the formula would classify costs of non-operating plants, such as WNP-1 and -3. Garman et al., PGP, E-PG-01, Appendix A, Exhibit 3, 1. The WWPUD's reply brief points out that the PGP method could cause rate instability, as various plants' plant factors vary. Reply Brief, WWPUD, R-WW-01, 16.

The DSI's discuss extensively in their opening brief why BPA should not use the TDLRIC Analysis results to classify thermal resource costs. Opening Brief, DSI, B-DS-01, 29-33. Three points are made there: (1) economic efficiency is not improved; (2) consumers do not make more informed decisions; and (3) short-term variations in cost are not smoothed out. The first point rests on the theory of second best, and is discussed extensively below under "Theoretical Considerations, Issue #6" of Chapter IV, and will be considered here only briefly. The theory of second best does not condemn marginal cost pricing, but simply points out some of the potential difficulties in such a pricing technique. These potential difficulties concern substitution away from, in this case, BPA power to goods and services that are not deliberately priced different from their respective marginal costs. "Deliberately" in this context means "as a result of public policy". Given that public regulation of most energy markets is pervasive, it is difficult to argue that BPA must account for a lack of perfect competition in those markets. That lack is already actually met by a variety of responses, and does not result, in reality, from a simple case of market imperfections. Therefore, BPA may proceed with marginal cost pricing without performing a detailed analysis of all impacts in markets for substitutes, which is all the theory of second best advocates at any rate.

The DSI's second point rests on the assumptions that end-use consumers' time horizons are shorter than BPA's long run, and that end-use retail consumers cannot and do not receive BPA's wholesale price signals. Neither of these assumptions invalidates BPA's actions. First, consumers are making decisions now that will affect energy consumption many years into the future, via the resulting stock of energy-producing and -consuming capital goods. Therefore, it is important that these current decisions reflect information about future electricity costs. The DSI's argue that BPA's customers must classify their own costs following BPA's results for the price signals to reach final consumers. This assumes that the only way for a wholesale utility to "pass along" a price signal is to mimic perfectly BPA's actions. Such an assumption ignores the fact that each wholesale customer of BPA faces a particular combination of loads, resources, and costs, and that these combinations are in no instance identical to the BPA system. Each utility must combine information about BPA rates, its own resources and its own load pattern, to determine optimal rates for its own system. BPA cannot dictate the behavior of its customers, nor should it. The price signals with which BPA is concerned occur in wholesale markets, not in retail markets. End-use consumers receive price signals that combine information on BPA's rates with considerations relevant at the local level for each utility. Therefore, classification at the retail level need not match wholesale classification perfectly.

The third DSI point is illustrated by the argument that the current energy surplus is aggravated by the application of LRIC classification results, a result that allegedly causes BPA's short run costs to vary more than they would with other classification methodologies. Opening Brief, DSI, B-DS-01, 32-33. This allegation ignores the fact that BPA's short run costs are overwhelmingly fixed, and cannot vary by perceptible amounts during the test period. Also, it is not clear how BPA's costs are affected by the quantity of surplus hydro power available, which seems to be the DSI argument. The amount of water net of firm load does not cause cost; it is merely a resource that may be sold.

Finally, the argument is made that the "LRIC methodology is not stable from year to year." Opening Brief, DSI, B-DS-01, 33. This is not strictly true. While it is true that the actual resources used to calculate the LRIC have changed since 1979, the resulting classification percentages have been stable, reflecting the simple fact that the region faces a long run situation in which the cost of an extra unit of energy is four to five times that of an extra unit of capacity, notwithstanding the technology used to provide the energy and capacity. This result should not be surprising, since at the margin all competing technologies should be roughly equally costly.

Decision

BPA's TDLRIC Analysis indicates that baseload thermal plants are being added in the future primarily to meet energy load growth. Further, the analysis also indicates that a relatively small portion of the baseload thermal plant costs is related to the additional capacity provided by the plant. Suggested methods such as fixed-variable and the PGP hydro-based formula do not reflect the cost causation of baseload thermal plant additions. Classifying thermal generation costs based on the TDLRIC Analysis is consistent with cost causation and reflects the characteristics of BPA's thermal generation costs. Thus, BPA will continue to classify thermal generation costs on the basis of the TDLRIC Analysis.

Issue #2

Should BPA classify some costs of Hanford to capacity?

Summary of Positions

BPA classifies 100 percent of the costs of Hanford to energy. BPA, E-BPA-05, Appendix D, D-4.

APAC states that a portion of Hanford costs should be allocated to capacity to reflect Hanford's use as a peaking resource and to reflect its historical plant factor. Cook, APAC, E-PA-02, 25; Opening Brief, APAC, B-PA-01, 61.

Evaluation of Positions

BPA classifies all Hanford costs to energy to reflect Hanford's operation. The plant produces energy as a by-product of the operation of the Department of Energy's plutonium production reactor. Consequently, BPA assumes it provides no dependable capacity. BPA, E-BPA-05, Appendix D, D-4.

APAC claims that Hanford is recognized as a peaking resource in the Northwest Power Pool Coordinating Group and reduces the forced outage reserves for four investor-owned utilities during operating year 1982-83. APAC claims that "BPA should estimate these capacity related costs." Cook, APAC, E-PA-02, 25. However, APAC fails to show how an analysis prepared for four IOU's for the Coordination Agreement dictates classification of BPA costs for its wholesale power rates. In its opening brief, APAC cites historical operation of Hanford to support its argument for classifying some of Hanford's costs to capacity. Opening Brief, APAC, B-PA-01, 61. BPA admittedly did not analyze the historical operation, including plant factor, of Hanford for the purpose of classifying costs. Opening Brief, APAC, B-PA-01, 61; Carr & Revitch, BPA, TR 5049-5050. APAC shows that Hanford has operated at a plant factor of near 50 percent in the last four years, and has been fully loaded at times of system peak. Cook, APAC, E-PA-02, Attachment HC-1, Schedules 7 and 8. Although the historical operation of Hanford shows its fairly regular contribution to capacity needs, BPA does not include Hanford in its resource planning for capacity. Revitch, BPA, TR 5049; BPA, E-BPA-03, Attachment 2, passim. The operating agreement for Hanford contains conditions which do not allow BPA to rely on Hanford for capacity needs. Carr, BPA, TR 5050. Historical operation cannot supersede these contractual conditions.

Decision

Although in practice Hanford has been operated in such a way as to provide capacity, contractual provisions do not allow BPA to rely on Hanford for capacity for resource planning purposes. Consistent with the principle of cost causation, BPA will continue to classify costs of Hanford 100 percent to energy.

d. Classification of Transmission Costs

Issue #1

Should BPA classify some transmission costs to energy in the COSA?

Summary of Positions

BPA classifies all transmission costs to capacity in the COSA. BPA, E-BPA-05, Appendix D, D-6; Carr & Revitch, BPA, E-BPA-28, 14; Revitch, BPA, TR 4972.

The WWPUD's recommend that BPA classify 50 percent of its transmission costs to energy, as a proxy until BPA prepares a cost causation study of transmission investment. Hutchison, et al., WWPUD, E-WW-01, 27.

APAC supports BPA's classification of transmission costs 100 percent to capacity. Cook, APAC, E-PA-08R, 10; Opening Brief, APAC, B-PA-01, 65.

Evaluation of Positions

The current transmission cost classification procedure used in BPA's COSA is consistent with accepted utility practice and with BPA's previous treatment of transmission costs. BPA, E-BPA-05, Appendix D, D-6. BPA did develop classification percentages based on peak and average demand for network transmission expenses in its 1983 initial TDLRIC Analysis. BPA, E-BPA-06, 19; BPA, E-BPA-06, Attachment 1, 195-206. This classification method was not adopted for BPA's COSA because it departed significantly from BPA's historical treatment, and because it focused only on the Network segment. Carr & Revitch, BPA, E-BPA-28, 14; Carr, BPA, TR 4973.

The WWPUD's recommend that BPA classify 50 percent of transmission costs to energy. They state three reasons for classifying a portion of costs to energy. First, transmission facilities interconnect various power supply systems, and thereby reduce generation reserve requirements. Second, transmission facilities connect remote plants to the power grid. Finally, transmission facilities are often oversized to reduce line losses. They state that all costs related to these three functions should be classified to energy. Hutchison, et al., WWPUD, E-WW-01, 27. Until BPA performs a study of cost causation, the WWPUD's recommend classifying 50 percent of transmission costs to energy as a reasonable approximation. Hutchison, et al., WWPUD, E-WW-01, 27. The reasons stated by the WWPUD's for classifying transmission costs to energy may be valid, but the 50/50 classification is arbitrary. BPA, E-BPA-06, Attachment 1, 198-201. The precedent stated by the WWPUD's for transmission costs being recovered from energy charges in the IR rate, Hutchison, et al., WWPUD, E-WW-01, 27, is a result of rate design procedures, not cost causation as analyzed in the COSA.

APAC criticizes both BPA's load factor method and WWPUD's 50/50 classification split by stating that transmisson plant is built to satisfy peak demands. Cook, APAC, E-PA-08R, 10; Opening Brief, APAC, B-PA-01, 65. Therefore, costs of transmission should be assigned in proportion to maximum demands placed on the system. Cook, APAC, E-PA-08R, 11. Other factors influencing transmission planning such as stability, load growth reserves, and losses are insignificant. Cook, APAC, B-PA-01, 65. Clearly, analysis of transmission cost causation is necessary before BPA can decide how much, if any, transmission costs should be classified to energy.

Decision

BPA believes that it may be appropriate to classify some transmission costs to energy, especially costs related to reducing line losses and to integrating baseload plants constructed to meet energy load growth. For BPA to depart from its historical classification method for transmission costs, however, the chosen method should be justifiable based on a reasoned approach. It should also be administratively feasible to implement and not unduly disrupt rate continuity. Until it discovers and tests such a method, BPA will continue to use the method that it has historically used to classify transmission costs.

e. Classification of Exchange Costs

Issue #1

How should BPA classify exchange generation costs?

Summary of Positions

In BPA's initial proposal, IOU exchange generation costs were classified based on classification information supplied by the IOU's themselves.

Revitch, BPA, TR 5029. On motion from the DSI's, BPA's testimony on exchange cost classification was struck from the record. Hearings Officer, TR 6933-6935. BPA then introduced supplemental testimony to classify IOU exchange generation costs based on a weighted average of FBS and NR classification percentages for generation. Carr & Revitch, BPA, E-BPA-28-2S, 1. Public Agency (PA) exchange generation costs are classified on the basis of the classification of Federal resource costs included in the Priority Firm rate. BPA, E-BPA-05, Appendix A, A-3; Carr & Revitch, BPA, E-BPA-28, 8-9. The classification of PA exchange costs was not a disputed issue in this rate case.

The DSI's supported BPA's use of FBS and NR classifications for exchange generation. Wilcox, DSI, E-DS-1, 41; Carter, DSI, E-DS-9, 11-12.

The WWPUD's recommend that BPA use the classification percentages developed in BPA's TDLRIC Analysis to classify exchange costs. Hutchison, et al., WWPUD, E-WW-01, 25; Opening Brief, WWPUD, B-WW-01, 36-40; Reply Brief, WWPUD, R-WW-01, 18.

PP&L's opening brief also supported the use of TDLRIC percentages. Opening Brief, PP&L, B-PL-01, 25-26.

Evaluation of Positions

BPA's classification of IOU exchange generation costs by weighted overall FBS and NR classification percentages is used as a proxy for how BPA would classify costs of exchange resources if they were owned and operated by BPA. IOU exchange resources represent a mix of thermal and hydro resources similar to BPA's mix of such resources. Carr & Revitch, BPA, E-BPA-28-25, 02.

The WWPUD's argument begins with the statement that the exchange resource should be treated as any other major resource on BPA's system. Hutchison, et al., WWPUD, E-WW-01, 25. The WWPUD's then suggest use of percentages developed in BPA's TDLRIC Analysis. Hutchison, et al., WWPUD, E-WW-01, 25. In support of the use of LRIC classification percentages, the WWPUD's reply brief suggests that the exchange resource is BPA's incremental resource because it is BPA's most expensive resource. Reply Brief, WWPUD, R-WW-01, 17. As pointed out by the DSI's, however, the exchange is similar to a purchased power transaction, Wilcox, DSI, E-DS-01, 41, in that BPA does not plan nor operate the exchange resource. The exchange is a "wash" from a load/resource balance standpoint, because the exchange resource equals the exchange load. BPA, E-BPA-05, 4. Thus, as the DSI's argue, the exchange does not require BPA to alter resource operation or to acquire new resources, Carter, DSI, E-DS-09, 11, and cannot itself be considered on incremental resource. A classification method for IOU exchange costs based on cost causation, as stated by the DSI's is thus the combined FBS and NR classifications. Carter, DSI, E-DS-09, 11-12.

PP&L supports use of TDLRIC classification percentages for all COSA costs. Opening Brief, PP&L, B-PL-01, 21. PP&L points out that BPA is unaware of what percentage of exchange resources operate as peaking resources, and of the ratio of hydro average generation during the critical period to total hydro baseload capability. Opening Brief, PP&L, B-PL-01, 26. As explained in cross-examination, however, BPA's method for classifying exchange costs is a proxy for an impractical exhaustive analysis, a proxy which BPA believes yields an accurate representation of cost causation. Carr & Revitch, BPA, TR 8378-8379.

Decision

The costs associated with the IOU exchange represent costs incurred by the IOU's for generation resources in a mix that is similar to BPA's mix of hydro and thermal resources. Consistent with the cost causation standard, the classification of the FBS and New Resource pools, therefore, represents a reasonable proxy for the classification of IOU exchange resources.

f. Classification of Conservation Costs

Issue #1

How should BPA classify conservation costs?

Summary of Positions

BPA classifies conservation costs based on values of energy and capacity calculated in the TDLRIC Analysis and the amounts of energy and capacity conserved. BPA, E-BPA-05, Appendix D, D-4.

APAC recommends that the portion of conservation costs allocated to BPA rates be classified on the basis of a weighted average of FBS, NR, and exchange classification percentages. Cook, APAC, E-PA-02, Attachment HC-1, Schedule 1.

Evaluation of Positions

BPA classifies conservation costs based on the LRIC of capacity and LRIC of energy calculated in its TDLRIC Analysis. It values capacity and energy savings at the avoided cost of the types of resources evaluated in the TDLRIC Analysis. BPA, E-BPA-05, Appendix D, 4-5. This method conforms with BPA's guideline for classification based on cost causation. The reasons that BPA incurs conservation costs relate to a need to avoid purchases of more expensive resources. BPA, E-BPA-05, Appendix G, G-18; Metcalf, BPA, E-BPA-30, 3. The APAC method classifies conservation costs in a manner similar to that for overhead costs. BPA, E-BPA-05, Appendix D, D-5. It values capacity and energy saved on the basis of resources already in place on BPA's system, rather than on an avoided-cost basis. This method does not reflect a cost causation approach to cost classification.

Decision

BPA's current method of classifying conservation costs is consistent with the principle of cost causation. The classification of conservation costs should not be influenced by the classification of BPA's embedded costs. The use of results from BPA's TDLRIC Analysis to determine the relative costs of capacity and energy implicit in conservation expenditures is appropriate and will be continued.

g. Classification of Deferral

Issue #1

How should BPA classify the deferral?

Summary of Positions

BPA functionalizes the deferral of prior years' interest expense between generation and transmission. The generation portion is then classified according to the weighted average classification of FBS, Exchange, and NR generation costs. BPA, E-BPA-05, Appendix D, D-6.

APAC recommends that the generation portion of the deferral be classified according to the weighted average classification of FBS, Exchange, NR, BPA's other generation costs, and conservation costs. Cook, APAC, E-PA-02, Attachment HC-1, Schedule 1.

Evaluation of Positions

BPA's method of classifying the deferral is administratively convenient. BPA's other generation costs and the deferral are classified by a weighted average of resource-pool related costs. BPA, E-BPA-05, Appendix D, 5-6. APAC does not discuss its proposed method for the deferral, nor offer any reasons for its use. Cook, APAC, E-PA-02, Attachment HC-1, Schedule 1. BPA's other generation costs, which are costs of BPA's general plant functionalized to generation and costs of resource options, are classified according to resource-pool related costs. They comprise less than 9 percent of generation costs, so their inclusion in calculating deferral classification would be insignificant. Also, the classification of conservation costs takes place after the classification of deferral, because of the conservation cost allocation method BPA uses. Thus, it is administratively infeasible to weight the classification of deferral by the classification of conservation costs.

Decision

BPA's method of classifying the deferral is administratively practical and reasonable. The changes proposed by APAC, which were never expanded upon, appear impractical. In addition, deferral classification would be insignificantly affected. Therefore, BPA continues to classify the deferral as proposed.

h. Classification of Resource Acquisition Costs

Issue #1

How should resource acquisition costs be classified?

Summary of Positions

BPA classifies resource acquisition costs using the classification percentages derived from its TDLRIC Analysis. BPA, E-BPA-05, Appendix D, D-4. This method reflects the fact that resource acquisitions are BPA's incremental resources.

APAC recommends that resource acquisitions be classified the same as FCRPS baseload costs, since most of resource acquisitions costs relate to the Idaho Falls hydro units. Cook, APAC, E-PA-02, Attachment HC-1, 4-5.

Evaluation of Positions

APAC states that most costs listed as resource acquisition costs relate to the purchase of the output of Idaho Falls hydro units. They state that these units operate like FCRPS baseload units, and therefore the associated costs should be classified in a similar manner. APAC claims that the proper classification percentages for resource acquisitions are 73 percent capacity and 27 percent energy. Cook, APAC, E-PA-02, Attachment HC-2, 5. The classification percentages preferred by APAC are those used by BPA to classify baseload hydro costs, reflecting cost causation of BPA's baseload hydro system. BPA, E-BPA-05, Appendix D, D-2. Resource acquisition purchases are made to serve load growth, and thus, represent BPA's incremental resources. Their cost causation and operation differ from those of baseload hydro generating plants. These differences should be reflected in the classification method used for resource acquisition costs.

Decision

The cost causation approach necessitates an examination of the reasons why costs are incurred. Resource acquisition costs are incurred to serve future load growth. The TDLRIC Analysis reflects the relationship between capacity and energy for resources added to meet future load growth. Therefore, because the resource acquisitions are incremental to BPA's other resources, the appropriate classification method for resource acquisitions is based on BPA's TDLRIC Analysis.

4. WPRDS Issues

a. Excess Revenues

Revenues from five sources (nonfirm energy sales, DSI top quartile pricing, Capacity/Energy Exchange, wheeling on the PNW-PSW Intertie, and energy transmission transactions) exceed allocated cost. An adjustment credits the excess to certain customer classes so that BPA does not overcollect its revenue requirement.

Issue #1

Should a greater percentage of excess revenue assigned to the FBS be classified to energy?

Summary of Positions

BPA classified the excess revenue assigned to the FBS using reverse TDLRIC generation percentages, 83 percent capacity and 17 percent energy. The result is that FBS costs are brought more in line with results that would have occurred had the TDLRIC classification been used for all costs. BPA, E-BPA-07, 14.

The BPA method is supported by the WWPUD's because it enhances the price signal sent by BPA's rates. Hutchison, et al., WWPUD, E-WW-02R, 31.

APAC argues that all excess revenue resulting from nonfirm sales should be classified to energy, because sales of nonfirm power are opportunity energy sales. Cook, APAC, E-PA-02, 55.

The PGP states that "since excess revenues result from the sale of surplus and nonfirm power resulting from operation of the system, the benefits should be classified in accordance with the cost associated with those resources", i.e., 35 percent to capacity and 65 percent to energy. Garman, et al., PGP, E-PG-01, 39-40.

The DSI's argue that "since excess revenues are generally <u>nonfirm</u> in nature . . . they should be classified 100 percent to energy. At the very least, they should be classified according to how the resource generating the excess energy is classified . . ." Carter, DSI, E-DS-19R, 21.

Evaluation of Positions

The reverse TDLRIC generation classification percentages are used to classify excess revenues because "the COSA classification process results in a greater percentage of FBS costs classified to capacity than would be indicated by the results of the TDLRIC." BPA, E-BPA-07, 13-14. In cross examination BPA stated that this classification procedure is "based upon the desire to better reflect the current relationship between the incremental cost of energy and the incremental cost of capacity." Metcalf, BPA, TR 7513. BPA's objective is, after crediting excess revenues, to have the classification of FBS costs more accurately reflect long-run incremental costs than does the COSA embedded-cost classification. The reverse TDLRIC classification meets this objective. BPA, E-BPA-07, 13.

APAC and the DSI's claim that any classification of excess revenues to capacity is "arbitrary" because those revenues generally result from sales of nonfirm energy. Further, no generation capability is in place for the sole purpose of generating nonfirm energy. Cook, APAC, E-PA-02, 54-55; Carter, DSI, E-DS-19R, 21. Even if classification of any costs to capacity were appropriate, the DSI's believe that use of the reverse TDLRIC percentage is arbitrary.

The DSI's argue in their reply brief that using TDLRIC classification percentages in the WPRDS undoes the COSA classification. Reply Brief, DSI, R-DS-01, 37-38. However, the purposes of classification in the COSA differ from the purposes of classification in the WPRDS. It is not inconsistent to have more than one classification methodology, because BPA must adjust rates to meet many purposes and to fulfill many criteria. Some of those purposes and criteria are contained in the WPRDS, where adjustments include an attempt to reflect TDLRIC Analysis results, and other purposes and criteria are contained in the COSA, where a great variety of resources are classified based on individual cost causation.

The use of the TDLRIC Analysis results in the WPRDS is supported by the WWPUD's, who argue that anomalies may thus be avoided. Reply Brief, WWPUD, R-WW-01, 18-19; Opening Brief, WWPUD, B-WW-01, 75-76. Specifically, embedded-cost classification percentages in the COSA may yield capacity rates above the LRIC of capacity, and energy rates below the LRIC of energy. Adjustments in the WPRDS allow this anomaly to be minimized, by reducing the energy rates less than the reductions in capacity rates.

APAC argues in its opening brief that all excess revenues resulting from nonfirm sales should be classified to energy. Opening Brief, APAC, B-PA-01, 87-89. There are three reasons supporting this argument. First, these sales only occur when greater-than-critical water happens, thus are purely energy sales and should be credited only to energy. Further, "[n]o generation capacity has been installed for the specific purpose of generating non-firm power." Opening Brief, APAC, B-PA-01, 88. While this may be true, it is also the case that neither has energy generating capability been installed for the specific purpose of generating nonfirm power. Therefore, since no installations at all have been built for the purpose of generating nonfirm power, intent at the time of construction is of no use in classifying nonfirm.

Second, APAC believes that reverse TDLRIC percentages for classifying excess revenue from nonfirm sales cannot be supported logically. They quote the PGP: "[t]he TDLRIC study requires that 83 percent of the revenues from secondary sales be classified to energy." Opening Brief, APAC, B-PA-01, 88, citing Garman, et al., PGP, E-PG-01, 56. APAC and the PGP appear to believe that a dollar of cost and a dollar of excess revenue are identical entities. This is clearly not the case, and to treat costs and revenues identically would itself be illogical. BPA uses reverse LRIC percentages to classify excess revenues because this results in a strengthening of LRIC price signals. BPA, E-BPA-07, 14. The result is to reduce capacity rates by a larger amount than the reduction in energy rates, thereby preserving the relationship between the prices of these two commodities.

Third, APAC believes that marginal cost principles "relate to the pricing of goods and services, not the classification of costs or income." Opening Brief, APAC, B-PA-01, 88. Accordingly, LRIC results should not, according to APAC, be used in any classification exercise. However, this ignores the fact that classification is a normal step in the derivation of electricity rates, and therefore cannot be separated from pricing except by drawing an arbitrary line. The further argument that sales of nonfirm energy from existing baseload hydro plants are unrelated to the thermal plants used in the TDLRIC study misses the point of applying the results of the TDLRIC Analysis, a point that is discussed extensively in Chapter IV, infra.

Decision

BPA will continue to use the reverse TDLRIC method to classify excess revenues to the FBS. It is important to develop rates that promote economic efficiency. Use of reverse TDLRIC classification percentages to credit excess revenues achieves this result because a greater proportion of excess revenues is credited to capacity than to energy, thus reducing the capacity rates more than the energy rates. The final rates are thus closer to LRIC rates.

b. Value of Reserves Credit

BPA provides a credit to the DSI's to reflect the value of the reserves which they provide to BPA's system. The resulting revenue deficiency is allocated to firm power classes of service.

Issue #1

How should BPA classify the value of reserves credit?

Summary of Positions

BPA classified the revenue deficiency 17 percent to capacity and 83 percent to energy following the percentages developed in the TDLRIC Analysis, to enforce the price signal sent by BPA's rates. Metcalf, BPA, E-BPA-32, 9. The DSI's proposed that the credit be classified 100 percent to capacity. Peseau, DSI, E-DS-10, 37-38.

Evaluation of Positions

The DSI's argued that the classification of the value of reserves revenue deficiency should recognize that the predominant cost component in the total value is related to capacity. As such, the entire revenue deficiency should be classified to capacity. Peseau, DSI, E-DS-10, 38. However, without the reserves provided by the DSI's, BPA would have to acquire resources. The resources thus acquired would have to provide power in a manner similar to that provided by all the types of interruptibility available via DSI contracts. It is prudent to assume that some of that power will have the characteristics of energy, and some will have the characteristics of capacity, and that this power will have to be available as firm. The characteristics of many resources make them unreasonable proxies for the resources that would have to be acquired in the absence of DSI restriction rights. The most reasonable proxy for firm power is the combination of resources identified in the TDLRIC Analysis. Further, these resources are the most efficient sources of firm power on a planning basis. Therefore, BPA uses the classification results of the TDLRIC Analysis to classify the value of reserves revenue deficiency.

Decision

The classification percentages used in the initial proposal have been retained. The percentages developed in the TDLRIC Analysis have been used to bring the results of the COSA classification of embedded costs closer to the relationship of the incremental costs of capacity and energy as shown in BPA's TDLRIC Analysis. By classifying the revenue deficiency resulting from the value of reserve credit in the manner proposed by BPA, the resulting rates move closer to reflecting the results of the TDLRIC Analysis. Energy rates are increased more than capacity rates, to reflect the fact that the LRIC of energy is much greater than the LRIC of capacity. Thus, the rates will send a more efficient price signal to BPA's customers than they would if the DSI's proposed method were adopted.

Summary of Positions

BPA incorporated a cash lag adjustment in its 1983 initial Revenue Requirement Study. This adjustment corrects for lags in the collection of revenue from sales in recognition of the delay between BPA's delivery of service and its receipt of payment for that service. It reflects the difference between the net cash lag occurring in the current year less the net cash that occurred in the previous year. Once the cash lag adjustment has been recovered in total in any particular year, it need not be recovered again but future adjustments may be necessary for incremental changes in the cash lag occurring in subsequent years. BPA, E-BPA-2, 62-63.

APAC has stated that BPA's ratepayers should not pay for a cash lag adjustment as an annual cost every year. APAC feels that since a cash lag was already financed by ratepayers in the rates developed as a result of the 1982 rate case, they should not be forced to pay a second time for the same cash lag adjustment. Cook, APAC, E-PA-02, 5; Opening Brief, APAC, B-PA-01, 26-27.

Evaluation of Positions

The cash lag adjustment in the Revenue Requirement Study does not double count the effect of the cash lag from year-to-year. Rather the cash lag adjustment reflects only the incremental change in the cash lag from year to year. This operation is detailed in E-BPA-24S, Attachment 2. If this provision for the change in the cash lag were not incorporated in the Revenue Requirement Study the necessary cash for scheduled amortization payments would not be available. Meyer, BPA, E-BPA-24, 9.

Decision

The cash lag adjustment is properly designed in that it does not double count the effects of the cash lag from year-to-year, but simply adjusts for the incremental change in the cash lag from year-to-year. This is an appropriate means of recognizing that there is a lag between the time service is delivered and the time that BPA receives payment.

Issue #3

Should the 5 percent internal financing provision act as an offset to the cash lag adjustment?

Summary of Positions

In the initial proposal the cash lag adjustment and the 5 percent internal financing provision are two separate and unrelated revenue requirement adjustments. Therefore, the provision for 5 percent internal financing would not decrease BPA's need for a cash lag adjustment. Meyer, BPA, TR 4116-4117. APAC maintains that financing 5 percent of investment from current revenues should lower the need for a cash lag adjustment since debt service is reduced. Cook, APAC, E-PA-02, 5; Opening Brief, APAC, B-PA-01, 27.

Evaluation of Positions

The purpose of the cash lag adjustment is to correct for the difference between accrual accounting and the cash receipts of the FCRPS. The provision for 5 percent internal financing of construction and conservation relates to BPA's needs as a self-supporting agency of the Federal government. The additional funds generated by the 5 percent financing provision will not, and is not intended to, correct for the difference between accrual accounting and the cash needs of the FCRPS.

Decision

The provision for 5 percent financing of construction and conservation from current revenues should not reduce the amount of the cash lag adjustment. The additional funds generated by the 5 percent financing provision will not, and is not intended to, correct for the difference between accrual accounting and the cash needs of the FCRPS. Consequently, both the 5 percent internal financing and the cash lag provisions are necessary.

C. Funding of Supply System Costs

Issue #1

Should BPA assume that construction and preservation costs for the Supply System are to be funded from current revenues or from bond sales.

Summary of Positions

In the initial proposal it was assumed that completion of WNP-1, -2, and -3 would be financed through the sale of bonds. Kallio, BPA, E-BPA-21, 5-6. This assumption was changed in supplemental testimony to reflect actions concluded by BPA with respect to financing future construction of WNP-1, -2, and -3. As a result, the revised Revenue Requirements Study reflects the assumption that BPA will finance WNP-2 directly from revenues and that WNP-3 will be put in a preservation state beginning June 1, 1983, with BPA paying ramp down/preservation costs when the WNP-3 construction fund is depleted. The Supply System has sufficient cash on hand through September 1985 to accomplish a 5-year construction delay for WNP-1. Kallio, BPA, BPA-21S, 1, 3.

The ICP maintains that given the Supply System's inability to finance WNP-1, -2, and -3, BPA should assume that the construction costs related to those units must be funded with current revenues. Prekeges, ICP, E-IC-05, 2.

Evaluation of Positions

The threshold issue of whether to continue the construction of WNP-2 has already been decided in a forum separate and outside of the rate case. What is at issue in the rate case is the revenue requirement associated with the continuation of WNP-construction. This subject is addressed in BPA testimony. Kallio, BPA, E-BPA-21S. The purpose of this testimony, and all other testimony concerning the revenue requirement associated with BPA's obligations, is to address the issue of whether BPA's rates yield revenues sufficient to repay the Federal debt and pay other costs. 16 U.S.C. §839e(a).

The issue of whether BPA has the authority to fund the construction of WNP-2 is the subject of a recent opinion of the Comptroller General of the United States. The Comptroller General concluded that BPA has congressional authority to pay directly for the construction costs of WNP-2. Opinion Letter to Senator McClure, No. B-210929, August 2, 1983. In analyzing this question, the Comptroller General indicated the payments are consistent with the purposes of the 1971 Public Works Appropriations Act and with BPA's broad contract and expenditure authority.

In essence, the Public Works Appropriations Acts, 1970 and 71, Pub. L. 91-144, 83 stat. 333 (1969) and Pub. L. 91-439, 84 stat. 899 (1970) reaffirmed BPA's authority to acquire the thermal generating capability of WNP-1, -2, and -3. As the Comptroller General indicated, "[s]uch Congressional recognition was not, however in derogation of any other existing authority BPA may have to acquire the generating capability of the thermal plants." Opinion Letter to Senator McClure No. B210929, August 2, 1983, at 7. <u>See also</u> Public Works for Water, Pollution Control, and Power Development and Atomic Energy Commission Appropriation Bill, 1971: Hearing on H.R. 18 127 Before the Subcommittee on Public Works on the House Committee on Appropriations, 91st Cong., 2d Sess. at 867-868.

In so reaffirming this authority to acquire and pay for the net-billing of the thermal generating capability of WNP-2, Congress also was aware that under certain circumstances, BPA would advance funds to project participants preceded by an Appropriations Act by Congress. 1971 House Appropriations Hearings at 871. As the Comptroller General indicated, the 1974 Transmission Act vitiated this understanding by establishing BPA as a revolving fund agency. 16 U.S.C. §838i(b)(6)(ii). Therefore, BPA can expend funds for this previously authorized acquisition absent an appropriation provided that (1) BPA has submitted the expenditure to Congress; and (2) it complies with the 1970-71 Appropriations Acts. Opinion Letter No. B.210929, August 2, 1983, at 7.

It is incorrect to argue that BPA's method which merely does directly what Congress authorized it to do indirectly in order to complete construction, is wrong. Such a position misreads Congress' intent and argues for a result that would cause destruction of the 1971 Appropriation Bill. The result of that view "would be to impute to Congress an intent to paralyze with one hand what it sought to promote with the other." <u>Weinburger v. Hynson, Westcot & Dunning</u>, 412 US 609, 631 (1973), <u>quoting</u> <u>Clark v. Vebersee Finance-Korp.</u>, 332 US 480, 489 (1947); <u>see</u> <u>Texas & Pacific Ry v. Abilene Cotton Oil Co.</u>, 204 US 426, 446 (1907) ("the act cannot be held to destroy itself"). In addition, when faced with more than one interpretation of a statute, the courts chose the interpretation consistent with the purpose of the statute. <u>National Petroleum Refiners Ass'n v. FTC</u>, 482 F.2d 672, 689 (D.C. Cir 1973), <u>cert. denied</u>, 415 US 951 (1974).

As previously noted and affirmed by the Comptroller General, BPA has independent statutory authority to pay for the costs of completing construction of WNP-2 in the power marketing statutes. This authority, coupled with BPA's broad contract and expenditure authority is contained in section 2(f) of the Bonneville Power Act, 16 U.S.C. §832a(f), as reaffirmed in section 9(a) of the Regional Act, 16 U.S.C. §839f(a), Reclamation Project Act of 1939, 43 U.S.C. §485h(e), Flood Control Act of 1944, 16 U.S.C. §825 and section 11(b) of the Transmission Act, 16 U.S.C. §838i(b). All of these acts have a common purpose and the Bonneville Project Act of 1937, Reclamation Project Act of 1939, and the Flood Control Act of 1944 should be read in pari materia to ascertain the intent of Congress. 41 Op. Att'y. Gen. 236 (1955).

Based on the above discussion, it is reasonable to conclude that BPA's use of its revenues to complete construction costs of WNP-2 is consistent with its statutory authority to acquire such project's thermal generating capability.

The ICP also suggests that BPA should reflect the construction of WNP-3 out of current revenues in the Revenue Requirement Study. Prekeges, E-ICP-05, 2. Moreover, the ICP argues that BPA's failure to account for its share of WNP-3 costs in the proposed rates is unlawful, and that they will pursue their rights with respect to WNP-3 in available forums. Opening Brief, PSP&L, B-PS-01, 9. Similar to the decision made to continue the construction of WNP-2, discussed above, the decision to ramp down construction and preserve WNP-3 was decided in a forum separate and outside of the rate case. Hence, any challenge as to the lawfulness of that decision may only be brought in forums other than this rate case. What is at issue in the rate case is the revenue requirement associated with ramp down and preservation costs. This subject is addressed in BPA testimony. Kallio, BPA, BPA-21S. As discussed above, the purpose of this testimony, and all other testimony concerning the revenue requirement associated with BPA's obligations, is to address the issue of whether BPA's rates yield revenues sufficient to repay the Federal debt and pay other costs. 16 U.S.C. §839e(a).

Decision

BPA adopts the treatment of Supply System costs reflected in BPA supplemental testimony. Kallio, BPA, E-BPA-21S. BPA believes that the revenue requirement identified in this testimony accurately reflects the impact of the decisions to continue construction of WNP-2 and to ramp down and preserve WNP-3.

D. Fish and Wildlife Program Costs

Issue #1

Is BPA obligated by law to fund all Columbia River Basin Fish and Wildlife Program measures, so that, notwithstanding other considerations, BPA's fish and wildlife program levels would provide for funding of capital improvements for fish mitigation at certain U.S. Army Corps of Engineers (COE) hydroelectric projects and all Yakima River Basin fish passage improvements?

Summary of Positions

BPA's direct case supports the fish and wildlife program levels in the Revenue Requirement Study with projections of the costs of Columbia River Basin Fish and Wildlife Program measures BPA expects to fund in fiscal years 1984 and 1985. Palensky, BPA, E-BPA-20, 1-2. These projections are based in part on BPA's expectation that the COE will fund through appropriations capital improvements for fish mitigation at certain of the COE hydroelectric projects. See Issue #1 in the Fish and Wildlife section of Chapter X, Participants Comments. The projections also are based in part on BPA's expection that some fish passage improvements in the Yakima River Basin called for by the Columbia River Fish and Wildlife Program will be funded by sources other than BPA. See Issue #3 of this section, below. The National Marine Fisheries Service (NMFS) contends that, notwithstanding all other considerations, BPA is obligated by law to fund the improvements at COE hydroelectric projects and all Yakima River Basin fish passage improvements, and so should provide in its fish and wildlife program levels sufficient monies to do so. Opening Brief, NMFS, B-NM-01, 5-7, 14-17, 18-19.

Evaluation of Positions

NMFS's contention that BPA should provide for funding capital improvements at COE hydroelectric projects and all fish passage improvements in the Yakima River Basin rests on the assertion that BPA is obligated to implement the Columbia River Basin Fish and Wildlife Program, per se. NMFS focus is misdirected.

NMFS incorrectly relies on section 4(h)(11)(A) of the Regional Act, 16 U.S.C. §839b(h)(11)(A). By its own terms, section 4(h)(11)(A) applies to the responsibilities of BPA and other federal agencies in the management and operation of the hydroelectric system on the Columbia River and its tributaries. Section 4(h)(10)(A), 16 U.S.C. §839b(h)(10)(A), not section 4(h)(11)(A), defines BPA's responsibilities with respect to use of the BPA fund to protect, mitigate, and enhance fish and wildlife affected by the development and operation of hydroelectric facilities on the Columbia River and its tributaries.

NMFS contends this interpretation is an "unduly narrow delineation of Bonneville's management authority, and is inconsistent with the doctrine of ejusdem generis." Reply Brief, NMFS, R-NM-01, 4. CRITFC's reply brief argues, however, that BPA's interpretation of section 4(h)(10)(A) is too broad and goes so far as to allege BPA's position is in reality a "veiled challenge to the program." Reply Brief, CRITFC, B-CR-02, 11. Both positions are untenable fcr the following reasons.

Ejusdem generis is a cannon of statutory construction designed to reconcile an incompatibility between an enumeration of specific words preceded or followed by a general reference supplementing the enumeration. The rule is used most typically to countervail other rules of construction such as, all words in a statute are to be given effect if possible; that parts of a statute are to be construed together; and that the legislature is presumed not to have used superfluous words. 2A Sutherland, Statutes and Statutory Construction §47.17 (4th Ed. 1973). Thus, if the series of specific words is given its full and natural meaning, the general words are redundant in part, Sutherland, supra at §47.17.

Section 4(b)(10)(A) does not contain an enumeration of specific words, nor does section 4(h)(11)(A) provide a general reference supplementing the enumeration. Moreover, no enumeration of specific terms was attempted in section 4(h)(10)(A). Section 4(h)(10)(A) and section 4(h)(11)(A) contain terms in themselves that are general and diverse in character from each other. By definition alone, the doctrine of ejusdem generis does not apply.

Section 4(h)(10)(A) does not require BPA to implement the Fish and Wildlife Program, per se. It directs the Administrator to:

> use the Bonneville Power Administration fund and the authorities available to the Administrator under this Act and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in the manner consistent with the [Northwest Conservation and Electric Power Plan] and [Columbia River Basin Fish and Wildlife Program] and the purposes of this Act. 16 U.S.C. §839b(h)(10)(A).

BPA's interpretation of section 4(h)(10)(A) does not misapprehend the applicable law and the intent of Congress, nor does it ignore the cannons of statutory construction as alleged by the NEDC. Reply Brief, NEDC, R-NE-01, 3.

The word "shall" does not impose on the Administrator an obligation to implement the program per se, but instead to "protect, mitigate, and enhance" fish and wildlife "in a manner consistent with" the program. Section 4(h)(10)(A) also creates a mandatory duty on the Administrator to consider factors other than the Fish and Wildlife Program, including assurance to the Pacific Northwest of an adequate, efficient, economical, and reliable power supply. 16 U.S.C. §839. Moreover, section 4(h)(10)(A) instructs the Administrator to use authorities under the Regional Act and other laws to protect, mitigate, and enhance fish and wildlife; it does not add new authorities. Consequently, it does not authorize the Administrator to implement program measures which require the exercise of authorities which reside in the COE or other agencies.

CRITFC alleges that Congress did not contemplate that general fund appropriations would be committed to carry out the Regional Act. Reply Brief, CRITFC, B-CR-02, 15. This argument ignores the express cost-sharing language of Congress:

> Consumers of electric power should bear only those costs attributable to electric power facilities and programs (but not the cost of measures designed to deal with impacts caused by other factors). . . . While the (Council's) program shall include directly only those measures needed to deal with impacts caused by power facilities and programs, it may be <u>integrated with similar efforts dealing with other impacts to the extent the administration and funding of such additional efforts are provided through other provisions of law or ancillary agreements</u>. (emphasis added). H.R. Rep. No. 96-976 (Pt. II), 96th Cong., 2d Sess. 45 (1980).

The PPC, in its reply brief also has stated this conclusion. Reply Brief, PPC, R-PP-01, 43-44. Noting that the Regional Act also requires the Administrator to balance the many purposes of the Act in a consistent manner, 16 U.S.C. §839, the PPC concluded the fish and wildlife provisions are intended to fit into the whole statutory framework of environmental laws and appropriations as expressed in section 4(h)(10)(A). Reply Brief, PPC, R-PP-01, 43-44.

NMFS's contention also ignores the fact that other Federal agencies share with BPA responsibility to protect, mitigate, and enhance fish and wildlife affected by hydroelectric development in the Columbia River Basin. Section 4(h)(11)(A) of the Regional Act, 16 U.S.C. §839b(h)(11)(A), applies to the COE, the U.S. Bureau of Reclamation (BOR), and the Federal Energy Regulatory Commission (FERC) as well as BPA, in the exercise of their responsibilities for managing, operating, or regulating Federal and non-Federal hydroelectric facilities in the Columbia River Basin. Section 4(h)(11)(A) directs these agencies to exercise their responsibilities "consistent with the purposes of this Act and other applicable laws, to adequately protect, mitigate, and enhance fish and wildlife . . . in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated . . . taking into account at each relevant stage of decisionmaking processes to the fullest extent practicable" the Columbia River Fish and Wildlife Program. 16 U.S.C. §839b(h)(11)(A).

NMFS's position asserting that BPA is obligated to implement the entire Fish and Wildlife Program would render section 4(h)(11)(A) of the Act useless. It is an elementary rule of construction that effect must be given, if possible to every word, clause and sentence of a statute. A statute should be construed so that effect is given to all its provisions so that no part will be inoperative or superfluous, void or insignificant. 2A Sutherland, <u>Statutes and Statutory Construction</u> §46.06 (4th Ed. 1973)

In addition, BPA believes that congressional authorization is a prerequisite of BPA funding of capital improvements for fish and wildlife mitigation within the authority of other federal agencies. To interpret 4(h)(10)(A) and related provisions of the Act as suggested by NMFS and CRITFC, would preempt Congressional authority to determine funding levels for a federal activity, and infringe on the individual agency's decisions on implementing the program. 16 U.S.C. §§1301 and 1347 embrace restrictions on appropriations and transfer of funds between agencies. Absent congressional authorization, these federal appropriation laws may preclude BPA from funding another Federal agency to perform substantially the same responsibilities the agencies are authorized to perform, but which go unfunded. Capital improvements for facilities managed and operated by the COE or BOR are substantially the same responsibilities the agency is authorized to perform. A contrary interpretation as suggested by the NMFS reply brief would result in BPA and the respective agencies second-guessing Congress as to the scope and level of funding of a project. As the PPC correctly stated, "BPA's authority does not extend to the funding of facilities which are within the authority of other agencies." Reply Brief, PPC, R-PP-01, 44.

Absent congressional approval one Federal agency may not reimburse another agency for the exercise of responsibilities the other is required by law to perform and for which as part of its purpose, it receives appropriations. 16 Comp. Gen. 333 (1956).

The contention that BPA should include funds for the COE projects in BPA's fish and wildlife program levels for direct BPA funding overlooks congressional appropriations and FCRPS repayment as appropriate sources of funding. In assigning new fish and wildlife funding responsibility to BPA, the Regional Act did not implicitly repeal the statutory responsibilities of other Federal agencies. H.R. Rep. No. 96-976 (Pt. II), 96th Cong., 2d Sess. 461 (1980). This includes the COE's responsibilities for Columbia River fish and wildlife protection, mitigation, and enhancement pursuant to section 4(h)(11)(A) of the Act. 16 U.S.C. §839b(h)(11)(A), directs the COE to exercise these responsibilities consistent with other applicable laws, which include appropriation laws. As the manager and operator of the John Day, the Dalles, Detroit, Blue River, and Cougar hydroelectric projects, primary responsibility for fish mitigation capital improvements at these projects rests with the COE. In addition, BPA cannot justify recovering the entire cost of the improvements, which are expected to total nearly $70 million, over the 20-month rate period when their useful life will extend many years into the future. By the device of repayment, the cost of FCRPS improvements are borne by ratepayers in future years who benefit from the power system over the life of the improvements.

Even assuming that BPA could directly fund the capital improvements at COE projects, section 4(h)(10)(B) of the Regional Act requires that the construction of capital facilities with an estimated life of greater than 15 years and an estimated cost of $1 million or more be funded in the same manner as "major transmission facilities" under the Federal Columbia River Transmission System Act, 16 U.S.C. §838. This requires that the expenditure of funds for such construction specifically be approved by an Act of Congress. 16 U.S.C. §838b(d).

Including funds for the improvements at the COE dams would duplicate funding Congress has already appropriated. The COE's FY 1984 appropriations include $13.8 million for completion of design and the initiation of construction of the bypass system at John Day Dam, and $180,000 for design and the initiation of construction of the vertical slot counter at The Dalles Dam. H.R. 98-272, Congressional conference Committee Report, FY 1984 Appropriations Bill, June 29, 1983. Because the counter is considered by the COE as an operation and maintenance expense, BPA is already reimbursing the U.S. Treasury for expenditures on the counter through FY 1983. The COE is examining the need for the Detroit, Cougar, and Blue River temperature control devices in a comprehensive Willamette System temperature control study that will extend through FY 1985. The COE does not expect construction of these devices, if undertaken, to begin until after FY 1985.

The Council's own fish and wildlife program acknowledges that COE funding of program measures at COE dams may be appropriate. Many program measures, including one for which the Council urges BPA to provide funds, E-NP-02, 4-5, section 404(b)(2), are addressed to the COE. <u>See</u> E-NP-02, sections 404(b)(1)-(20), 604(a)(5), 604(b)(2), and 804(e)(9). Section 1304(e)(2) of the program states that, "[i]n those instances in which the Council has specified in this program that BPA shall fund a program measure at a federal project, BPA immediately shall initiate discussions with the appropriate federal project operator and the Council to determine the most expeditious means for funding each measure." E-NP-02, 13-4, section 1304(e)(2).

The purpose of BPA testimony concerning fish and wildlife program levels is to substantiate the revenue requirement in the rate case, not to justify BPA's fish and wildlife responsibilities. The hearing requirements of section 7(i) of the Regional Act do not place BPA's individual programs at issue. To provide such programmatic justification would necessitate going far beyond the scope of the ratemaking process. The purpose of testimony concerning BPA's revenue requirements is to examine on the record whether BPA's rates satisfy section 7(a)(1) of the Regional Act, not to justify every program that contributes to BPA's costs. 16 U.S.C. §839e(a)(1).

<u>Decision</u>

Aside from the considerations addressed under Issue #3, below, and under the fish and wildlife section Issue #1 of the chapter evaluating participants comments of this Record of Decision, BPA is not obligated by law to provide for funding of capital improvements for fish mitigation at COE hydroelectric projects or for all fish passage improvements in the Yakima River Basin.

Issue #2

Should BPA's fish and wildlife program levels provide for accelerated implementation of certain Yakima River Basin anadromous fish passage improvements?

Summary of Positions

BPA's direct case supports the fish and wildlife program levels in the Revenue Requirement Study with projections of the cost of implementing Columbia River Basin Fish and Wildlife Program measures. Palensky, BPA, E-BPA-20, 1-2. The projections for anadromous fish passage improvements in the Yakima River Basin total $149,000 in FY 1984 and $1,194,000 in FY 1985. Palensky, BPA, E-BPA-20, revised Attachment 2, 6. In turn, these cost projections are predicated on the expected schedule for the implementation of Yakima River Basin passage improvements. Palensky, BPA, TR 3579-3580; Palensky, BPA, E-BPA-20, Attachment 7.

The Columbia River Inter-Tribal Fish Commission (CRITFC) asserts that BPA's fish and wildlife program levels should provide for earlier implementation of certain Yakima River Basin fish passage improvements. In contrast to the schedule on which BPA's cost projections are predicated, CRITFC asserts that the Sunnyside and Wapato projects will be fully implemented by the end of FY 1985. Dompier, CRITFC, E-CR-01R, 4-8. BPA's projections provide for preliminary investigations in FY 1984 and designs and specifications in FY 1985, with construction after FY 1985. Palensky, BPA, E-BPA-20, Attachment 7, 1-3. CRITFC also asserts that preliminary investigations, designs, and specifications for the Taneum, Toppenish, Toppenish/Status, Upper Toppenish, and Marion Drain projects will take place in FY 1985. Dompier, CRITFC, E-CR-01R, 4-8. BPA's projections are based on initiation of these projects after FY 1985. Palensky, BPA, E-BPA-20, Attachment 7, 4. In combination with increases addressed under Issue #3, below, this accelerated schedule justifies providing for $3 million for Yakima River Basin anadromous fish passage improvements in FY 1984 and $16.2 million in FY 1985. Dompier, CRITFC, E-CR-01R, 9.

The National Marine Fisheries Service (NMFS) also urges BPA to provide for funding all of the Yakima Basin fish passage improvements, apparently following the schedule proposed by CRITFC. Opening Brief, NMFS, B-NM-01, 17, 19. NMFS also asserts that the Preliminary Implementation Plan, which BPA used in projecting the costs of Yakima Basin fish passage improvements, has been revised to incorporate the schedule proposed by CRITFC. Opening Brief, NMFS, B-NM-01, 4, 17.

Evaluation of Positions

The BPA position agrees with the CRITFC and NMFS position on the cost of the Yakima Basin fish improvements at issue, but disagrees on the implementation schedule (timing of the costs). In projecting costs, BPA relied on the "Preliminary Implementation Plan for the Columbia River Basin Fish and Wildlife Program" (Preliminary Implementation Plan). This plan is a report of an interagency implementation planning process coordinated by the NMFS. See NMFS, E-NM-01. BPA also relied on a supporting document entitled "Yakima Basin Draft Team Report" (Draft Team Report) (see Dompier, CRITFC, E-CR-01R, Appendix 1). Palensky, BPA, E-BPA-20, 2-3 and Attachment 7; Palensky, BPA, TR 3582, 3596-3597. However, BPA adjusted the expected timing of project implementation to account for factors the Preliminary Implementation Plan and Draft Team Report did not consider. Palensky, BPA, E-BPA-20, 2-3 and Attachment 7; Palensky, BPA, TR 3596-3597.

BPA may pay for pre-engineering work on capital fish facilities prior to congressional authorization and appropriation. The language of section 4(h)(10)(B) of the Regional and 4(d)(ii) of the Federal Columbia River Transmission System Acts requires congressional approval only before construction commences. 16 U.S.C. §838b(d)(ii). BPA agrees with CRITFC reply brief on this point. Reply Brief, CRITFC, B-CR-02, 19. Design is a precursor of construction. However, section 9(b) of the Regional Act requires implementation of the Act in a sound and businees-like manner, thereby suggesting a legal basis for conducting design work prior to congressional approval. There will be circumstances where expenditures for design work prior to Congressional approval will fall within the concept of an expenditure made in a legally sound and business-like requirement, but this determination must be made on an individual basis encompassing both law and policy decisions.

Regarding the Sunnyside and Wapato projects, BPA testimony states that design will not be initiated until congressional approval is initiated, that the necessary legislation will not be enacted early enough to permit both preliminary investigations and design in FY 1984, and that project design will not be completed until the end of FY 1985. Palensky, BPA, E-BPA-20, 103, and Attachment 7. CRITFC provides no rebuttal of these conclusions.

BPA's cost projections for the Taneum, Toppenish, Toppenish/Status, Upper Toppenish, and Marion Drain projects, rely on the timetable and reasoning in the Preliminary Implementation Plan and Draft Team Report. This report calls for commencement of design work on these projects in FY 1986. Palensky, BPA, E-BPA-20, Attachment 7. In support of earlier commencement of these projects, CRITFC relies on a schedule "developed through informed consultation among representatives from the Washington Department of Fisheries, the Washington Department of Ecology, the Yakima Indian Nation, the Columbia River Inter-Tribal Fish Commission, the National Marine Fisheries Service, the Bureau of Reclamation, and the Northwest Power Planning Council." Dompier, CRITFC, E-CR-01R, Appendix 2, 1. According to CRITFC, this schedule is generally accepted in the "biological community." Dompier, CRITFC, E-CR-01R, 8. NMFS and CRITFC state that the Preliminary Implementation Plan has been revised since its distribution in April 1983 to incorporate the schedule for Yakima Basin improvements proposed by CRITFC. Opening Brief, NMFS, B-NM-01, 4, 17; Reply Brief, NMFS, B-NM-02, 6-7; Reply Brief, CRITFC, B-CR-02, 12-14.

The arguments of CRITFC and NMFS do not withstand scrutiny. The schedule favored by CRITFC differs from the schedule in the NMFS Preliminary Implementation Plan, even though both were distributed in April 1983.

Dompier, E-CR-01R, Appendix 2; Palensky, BPA, E-BPA-20, Attachment 7, 2. This demonstrates that views within the "biological community" differ. In addition, BPA did not base its cost projections solely on the Preliminary Implementation Plan or solely on biological considerations. BPA independently reviewed the Implementation Plan and considered other factors, including the time that might be needed for additional legislative consideration and administrative satisfaction of Federal procurement and environmental requirements. Palensky, BPA, E-BPA-20, 3 and Attachment 7. Furthermore, the appendices on which CRITFC relies contain no reasons for beginning the Taneum, Toppenish, Toppenish/Status, Upper Toppenish, and Marion Drain projects in FY 1985 instead of later. Dompier, CRITFC, E-CR-01R, Appendies 2 and 2A. CRITFC argues in its reply brief that the Fish and Wildlife Program's direction to give priority to projects in the lower Yakima River provides a basis for the accelerated schedule CRITFC and NMFS urge. Reply Brief, CRITFC, B-CR-02, 14, citing E-NP-02, 9-5. This is not the case. This direction addresses the sequencing of projects, not their scheduling. In sequencing, BPA's cost projections are consistent with what CRITFC urges.

CRITFC and NMFS are unjustified in asserting that the Preliminary Implementation Plan has been revised to incorporate the schedule contained in Appendix 2 of CRITFC's rebuttal testimony. Dompier, CRITFC, E-CR-01R. First, their assertion is unsupported by evidence in the record that the plan has been revised. Appendix 2 of CRITFC's rebuttal testimony is simply a letter from a member of the Northwest Power Planning Council staff seeking comments on a proposed schedule. <u>See</u> Dompier, CRITFC, E-CR-01R, Appendix 2. Neither NMFS nor CRITFC offers any documentary evidence that the plan was revised. Second, BPA is in receipt of a July 6, 1983, memorandum from NMFS transmitting revisions to the Preliminary Implementation Plan. This memorandum states that "[t]here were no changes made to the Section 900 draft." Section 900 of the Fish and Wildlife Program addresses the Yakima River Basin. NMFS's own actions contradict its representations.

<u>Decision</u>

BPA's proposed fish and wildlife program levels are sufficient to cover the cost of Yakima River Basin fish passage improvements which BPA expects to fund in FY 1984 and FY 1985. The proposed fish and wildlife program levels are supported by cost projections based on reasonable expectations regarding the schedule for Yakima River Basin fish passage improvement implementation.

<u>Issue #3</u>

Should BPA's fish and wildlife program levels provide for funding of certain Yakima River Basin anadromous fish passage improvements by BPA?

<u>Summary of Positions</u>

The cost projections supporting the fish and wildlife program levels in the BPA Revenue Requirement Study do not include costs for the Prosser, Roza, Easton, Horn Rapids, or Naches Cowiche projects. BPA expects the U.S. Bureau of Reclamation (BOR) to fund the Prosser and Roza projects through appropriations. Because these are Federal Columbia River Power System facilities, once the fish passage improvements are completed, BPA will repay to the U.S. Treasury the power share of their costs. Such repayments are outside BPA's fish and wildlife program levels. Palensky, BPA, E-BPA-20, Attachment 7, 1. Based on statements of BOR and Washington Department of Ecology (WDOE) officials, BPA understands that these agencies will fund the Easton and Horn Rapids projects. Palensky, BPA, E-BPA-20, Attachment 7, 1, 4; Dompier, CRTIFC, E-CR-01R, Appendix 4. Based on a statement by a BOR official, BPA understands that the City of Yakima will fund the Naches Cowiche project. Palensky, BPA, E-BPA-20, Attachment 7, 4.

CRTIFC and NMFS urge that BPA's fish and wildlife program levels be increased to provide for funding by BPA of the Prosser, Roza, Easton, Horn Rapids, and Naches Cowiche projects. Dompier, CRITFC, E-CR-01R, 5-7, 9; Reply Brief, CRITFC, B-CR-02, 15-18, 21-22; Reply Brief, NMFS, B-NM-02, 8-9. This is because, other than an offer by the City of Yakima to fund part of the Naches Cowiche project, no written offers of funding exist and no Federal appropriations legislation for FY 1984 contains funding for Yakima Basin improvements. Dompier, CRITFC, E-CR-01R, 8; Opening Brief, CRITFC, B-CR-02, 15; Opening Brief, NMFS, B-NM-02, 8.

Evaluation of Positions

Regarding the Prosser and Roza projects, the BPA case explains why funding for these projects will not fall within BPA's fish and wildlife program levels. CRITFC offers no evidence disputing the propriety of BOR funding of these projects with BPA repayment of the power share of their cost. CRITFC refers to provisions of the Fish and Wildlife Program urging BPA to consult with the BOR regarding the funding of improvements at BOR facilities. Opening Brief, CRITFC, B-CR-02, 17-18; Opening Brief, NMFS, B-NM-02. BPA's case is based on the expectation that the BOR will fund the Roza and Prosser improvements through appropriations. Palensky, BPA, E-BPA-20, Attachment 7. BPA is in a far better position to predict the arrangements for these projects than is the CRITFC.

Regarding the Easton and Horn Rapids projects, BPA's case does not provide documentary evidence of the availability of funds from the BOR and WDOE to fund these projects. However, the BPA case does cite oral representations by officials of these agencies that they will provide funding for the projects. Moreover, CRITFC offers no evidence whatsoever that these agencies will not provide funding. Palensky, BPA, E-BPA-20, Attachment 7; Dompier, CRITFC, E-CR-01R, 8.

In the case of the Naches Cowiche project, BPA's case relies on the secondhand report of the City of Yakima's intentions to fund improvements at the Naches Cowiche diversion dam. CRITFC's rebuttal testimony presents a letter from the City of Yakima offering to fund a part, but not all, of the Naches Cowiche project. Dompier, CRITFC, E-CR-01R, Appendix 3. However, this letter is not addressed to BPA and the letter is a request, not a statement of the City's intention not to fund the Naches Cowiche project. In fact, the letter implies that the City of Yakima itself earlier planned to pay for the Naches Cowiche project, in conjunction with the Naches Cowiche Canal Company. Dompier, CRITFC, E-CR-01R, Appendix 3. CRITFC offers no evidence that the City of Yakima or any other party has requested BPA to fund a portion of the Naches Cowiche project, or that BPA has agreed to do so.

Decision

BPA's fish and wildlife program levels do not provide for BPA funding of the Prosser, Roza, Easton, Horn Rapids, or Naches Cowiche projects. The cost projections supporting these program levels reasonably conclude that BPA's contribution to the Prosser and Roza projects will be through repayment to the U.S. Treasury of the power share of their costs, which is outside BPA's fish and wildlife program levels. They also reasonably conclude that BPA will not provide funding for the Easton, Horn Rapids, and Naches Cowiche projects in FY 1984 or FY 1985. Rebuttal testimony does not provide grounds for modifying these conclusions, or for increasing BPA's fish and wildlife program levels to provide for BPA funding of the projects at issue.

Issue #4

Should the rate case revenue forecast assume that BPA will replace power losses incurred by the Idaho Power Company (IPC) resulting from operation of the Brownlee project to meet Water Budget flows.

Summary of Positions

BPA's rate case Revenue Forecast Study, E-BPA-4, assumes that BPA will replace power losses incurred by IPC resulting from operation of the Brownlee project to meet Water Budget flows. Dean, BPA, E-BPA-19, 7-8; McLennan, BPA, E-BPA-18, 6. BPA expects to replace IPC's power losses because (a) Brownlee is one of only two major reservoirs capable of supplying water to meet Water Budget flows at Lower Granite Dam; and (b) BPA believes that IPC will not voluntarily operate Brownlee to provide Water Budget flows if IPC suffers a loss in power capabilities or revenues, or an increase in the cost of operating its power resources. Dean, BPA, E-BPA-19, 7. BPA does not expect to replace any power losses incurred by the Mid-Columbia PUD's and has not provided for replacing such power losses in the rate case. McLennan, BPA, E-BPA-18, 6. BPA will initiate an administrative process to determine what portion of IPC's and the Mid-Columbia PUD's power losses are attributable to the development and operation of their projects. McLennan, BPA, E-BPA-18, 6.

PPC asserts that providing for the replacement of IPC's power losses prior to determining the compensable portion: (a) violates prudent utility practice by imposing costs on BPA customers for which BPA may not be liable; (b) is inequitable because it treats some non-Federal project owners more favorably than others; and (c) is contrary to the Columbia River Basin Fish and Wildlife Program. Wolverton, PPC, E-PP-01, 17-8.

Evaluation of Positions

PPC's position is that BPA should make no provision for replacement of power losses whatsoever until the compensable portions are determined. This would result in a revenue shortfall because BPA expects to replace IPC's power losses. Ratesetting necessitates reasonable assumptions. In the absence of foreknowledge of the compensable portions, it is reasonable to assume full compensation of IPC's power losses and no compensation of the Mid-Columbia PUD's power losses. Moreover, failure to provide for replacement of IPC's power losses would be tantamount to abrogating the Administrator's responsiblities under section 7(a)(1) of the Regional Act, 16 U.S.C. §839e(a)(1). Failure to anticipate costs in the revenue forecast would result in revenue underrecovery and thus violate the sound business principles mandate of section 7(a)(1).

The assumption of full compensation of IPC's power losses is not inequitable because, as the PPC acknowledges, Water Budget releases from Brownlee will mitigate adverse effects caused by projects other than the Hells Canyon Complex, and BPA does not consider the position of the Mid-Columbia PUD's to be the same as IPC's. Wolverton, PPC, TR 6252; McLennan, BPA, E-BPA-18, 6. In addition, the assumption does not foreclose less than full replacement of IPC's power losses or partial replacement of the Mid-Columbia PUD's power losses.

PPC's reliance on section 304(a)(5) of the Columbia River Basin Fish and Wildlife Program is misplaced. BPA's authority to compensate IPC's power losses flows from the Regional Act, not from the Columbia River Basin Fish and Wildlife Program. Section 4(h)(11)(A)(ii) of the Act directs BPA to bear any costs and power losses of a non-Federal electric power project resulting from the imposition by a Federal agency of a measure pursuant to the agency's responsiblities under section 4(h)(11)(A), if and to the extent that such measure is not attributable to the development and operation of the non-Federal project. 16 U.S.C. §838b(h)(11)(A). In addition, BPA believes that section 4(h)(10)(A) also provides authority to compensate costs and power losses at non-Federal electric power projects. When determined by the Administrator to be necessary and appropriate to meet BPA's responsibilities pursuant to section 4(h)(10)(A), BPA may compensate a non-Federal electric power project for costs and power losses resulting from measures not attributable to the non-Federal project. To be compensable by BPA under section 4(h)(10)(A), costs or power losses need not result from measures imposed by another Federal agency. 48 FR 20117, May 4, 1983. The discharge of BPA's compensation authorities under sections 4(h)(10)(A) and 4(h)(11)(A)(ii) of the Act is the responsibility of the Administrator. Compensation is not within the authorized scope of the Fish and Wildlife Program. 16 U.S.C. §838b(h)(2).

Decision

Providing in the revenue forecast for replacement of IPC's power losses resulting from releases of water from Brownlee Reservoir to meet Water Budget flows represents a reasonable assumption. In view of BPA's intention to determine whether some of IPC's power losses are not compensable and whether some of the Mid-Columbia PUD's power losses are compensable, the assumptions made by BPA could well be offsetting. The assumptions are equitable and consistent with BPA's legal responsibilities.

E. Appropriate Cost Recovery

Issue #1

Whether BPA incorrectly relied on DOE Order RA 6120.2 as the basis for requesting the $126 million increase?

Summary of Positions

In supplemental testimony BPA indicated that a change was necessary in the method used in the initial proposal to derive the 20-month rate period (November 1, 1983, through June 30, 1985) revenue requirement. Carr & Meyer, BPA, E-BPA-57, 1. As discussed elsewhere, this change was necessary since revenues derived from rates using the methodology contained in the initial proposal would be insufficient to meet the FY 1984 revenue requirement, resulting in a revenue shortfall for FY 1984 of approximately $126 million. The revenue requirement for FY 1984 and FY 1985 would not be effected by this change in methodology. Carr & Meyer, BPA, E-BPA-57, 2.

SCE makes a number of points regarding BPA's application of DOE Order RA 6120.2 in the context of proposing the $126 million increase in its revenue requirements. RA 6120.2 establishes financial reporting policies, procedures and methodology for all DOE power marketing administrations. First, SCE questions the applicability of DOE Order RA 6120.2 to BPA given the changes in the Administrator's authority as a result of the Regional Act. Opening Brief, SCE, B-CE-01, 27. Second, SCE states that Order RA 6120.2 does not require that BPA raise its rates to meet an increased repayment obligation. SCE maintains that BPA should have investigated other viable means for meeting its cost recovery criteria such as decreasing costs and changing contracts. Opening Brief, SCE, B-CE-01, 28. Third, BPA's cumulative deferral for 1985 would not change if the staff's proposal were rejected. Opening Brief, SCE, B-CE-01, 29. Fourth, the $126 million increase violates the procedural safeguards of Section 7(i) of the Regional Act. Reply Brief, SCE, R-CE-01, 44.

Evaluation of Positions

DOE Order RA 6120.2 consists of regulations promulgated pursuant to the Flood Control Act, the Bonneville Project Act, and the Federal Columbia River Transmission System Act, among other statutes. RA 6120.2, §5. These statutes, in addition to the Regional Act, require BPA to collect revenues sufficient to repay the Federal investment. See §7(a) of the Regional Act. 16 U.S.C. §839e(a). The stated purpose of 6120.2 is "[t]o establish financial reporting policies, procedures, and methodology for all Department of Energy (DOE) power marketing administrations (PMA's) except where deviations therefrom are specifically approved by the Secretary, authorized by statute, or identified and explained in a transmittal memorandum or in the footnotes to the reports." §1 of 61202. Hence, as a general proposition, 6120.2 is applicable to BPA's repayment procedure and methodology. See §6(b), 7(f), 8(c), 10, 12 of 6120.2.

SCE's suggestion that 6120.2 is inapplicable to BPA because interim rate approval authority is no longer exercised by the Assistant Secretary of DOE, is inapposite. The shift of interim approval authority from the Assistant Secretary to the FERC, provided for in section 7(i)(6) of the Regional Act, does not affect the applicability of 6120.2 to BPA. 16 U.S.C. §839e(i)(6).

SCE has stated that BPA should have engaged in cost cutting measures and contract changes prior to proposing an increase in rates in order to meet its cost recovery criteria. Opening Brief, SCE, B-CE-01, 28. BPA has already engaged in cost cutting measures. On February 18, 1983, the Administrator announced a 30-day delay in publishing BPA's initial rate proposal. At that time, he challenged the Supply System to reduce its cash requirements through June 1985 on WNP-1, -2, and -3. Kallio, BPA, E-BPA-23, 3. The Administrator also took that opportunity to ask all BPA offices to review program levels, revising them where necessary, to hold down costs and thus, the level of the proposed rate increase. Hickey, BPA, E-BPA-14, 2. As a result, BPA's current revenue requirement proposal incorporates significant reductions in program levels from the revenue requirement reflected in the congressional budget. Pizza, BPA, E-BPA-22, 3; BPA, E-BPA-2, 11.

Finally, SCE suggests that BPA's cumulative deferral for 1985 would not change if BPA staff's proposal were rejected. Opening Brief, SCE, B-CE-01, 29. Such a result is possible because DOE Order RA 6120.2 requires that BPA eliminate any outstanding deferral before making planned amortization payments. However, a $126 million underrecovery of BPA's revenue requirement would lead to a reduction in amortization payments. This would not be in accordance with the Administrator's decision to pay all regularly scheduled amortization for FY 1984 and FY 1985. Meyer, BPA, E-BPA-24, 13; Meyer, BPA, E-BPA-24S, 6-7.

Decision

DOE Order RA 6120.2 is clearly applicable to BPA, subject to the above noted exceptions. The rates developed for the initial proposal incorporated an explicit attempt to minimize costs. As a result, SCE's argument that costs be minimized has already been instituted in this rate proposal. Finally, SCE suggests that BPA's cumulative deferral for 1985 would not change if the BPA proposal were rejected. However, the rejection of the proposal would mean that planned amortization payments would not be made in full. This result is not in accord with BPA's intent to pay all regularly scheduled amortization payments for FY 1984 and FY 1985.

Issue #2

How should prior underrecoveries of transmission costs be recovered from present ratepayers?

Summary of Positions

In the initial proposal prior underrecoveries of transmission and power rates not recovered in prior rates since 1976 are included in the 1983 revenue requirement. Diffely, BPA, TR 6178. Part of the revenue requirement is functionalized to transmission. Therefore, the transmission revenue requirement includes a portion of the power and transmission rate deficiencies for the period from 1976 to 1983. Meyer, BPA, E-BPA-55R, 4. The DSI's maintain that BPA should recover the prior underrecovery of transmission costs through its transmission rates. Wilcox, DSI, E-DS-01, 32. The DSI's rely upon the Federal Energy Regulatory Commission's August 3, 1982 Order Confirming and Approving Transmission Rates (Docket No. E-9563-000).

Evaluation of Positions

The DSI's interpretation of the Commission's order supports the proposition that it is appropriate to account separately for the deficits associated with transmission rates. This would in essence require a locking-in of functionalization percentages. The relative uses of the BPA transmission system for Federal and non-Federal power, however, vary because of the dynamic nature of the marketplace. If an overly-rigid approach of assigning prior deficits to particular customer classes is followed, it may result in deficits remaining unrecovered in the event of significant changes in the usage of a customer class. Customers pay if they make use of BPA's facilities. However, if their usage decreases or stops, they do not necessarily have an obligation to pay for yet unrecovered costs. Meyer, BPA, E-BPA-55R, 4. The approach advocated by the DSI's is generally not in accord with standard utility practice and may in the long run frustrate BPA's statutory obligation to recover the Federal investment.

BPA recognizes that there have been underrecoveries of BPA transmission and power revenue requirements in prior years. In accordance with the Commission's order approving BPA's 1976 transmission rates, underrecoveries associated with prior rates are included in BPA's 1983 revenue requirement. Since a part of BPA's 1983 revenue requirement is functionalized to transmission, the transmission rates include a share of the revenue deficiencies associated with the period that the 1976 transmission rates were in effect. BPA believes that this approach results in an equitable allocation of costs between Federal and non-Federal customers, in compliance with section 7(a)(2)(C) of the Regional Act. 16 U.S.C. §839e(a)(2)(C).

Decision

BPA has properly recovered prior underrecoveries of transmission costs.

F. Residential Exchange and ETCA Cost Projections

1. Introduction

The Residential Exchange program was implemented according to section 5(c)(2) of the Regional Act. The residential exchange program incorporates the Average System Cost (ASC) methodology developed by BPA in consultation with its customers, State regulatory bodies in the region, and the Pacific Northwest Power Planning Council. The ASC methodology sets forth the method for computing "average system cost," the costs allowed or established for retail ratemaking that are eligible for exchange divided by the kilowatthours of load assumed for retail ratemaking, including certain adjustments.

The Exchange Transmission Credit Agreement (ETCA) gives BPA utility customers an opportunity to receive benefits for their transmission systems which they would have received under a Residential Exchange Agreement without actually entering into a purchase and sale of resources with BPA under the Residential Exchange Agreement. BPA offered the ETCA to its utility customers on February 22, 1983.

BPA developed a methodology to forecast investor-owned utility residential exchange costs that incorporates the use of an average annual rate of growth (AARG) factor. The AARG was determined by disaggregating and projecting the major components of each utility's ASC. This AARG in ASC was applied to BPA's estimate of each utility's ASC in effect or anticipated to be in effect during FY 1983 in order to project an ASC for each utility through FY 1985.

BPA also analyzed public agencies to project their eligibility for both the residential exchange and the ETCA. This analysis incorporated major system cost components including power purchases from BPA, transmission expense, other resource costs, and residential/small farm load.

These analyses of investor-owned and public agency utilities resulted in residential exchange and ETCA cost projections that are used in BPA's Revenue Requirement Study, Cost of Service Analysis, and in BPA's Wholesale Power Rate Design Study.

2. Projection of Investor-Owned Utilities' ASC Through FY 1985

BPA incorporates numerous assumptions and forecasting techniques in projecting investor-owned utilities' ASC through FY 1985. Issues related to these assumptions and techniques are described below.

a. Estimate of IOU's FY 1983 ASC

Issue #1

Should BPA's estimate of IOU's FY 1983 ASC exclude power cost adjustments for two IOU's?

Summary of Positions

The exchange cost estimates presented in BPA's initial proposal included the power cost adjustments in the FY 1983 ASC's of Portland General Electric and Puget Sound Power & Light which were used as a base to arrive at projections of ASC for FY 1984 and FY 1985. BPA, E-BPA-2, Attachment 1, Ch. IV, B-3. In BPA's supplemental testimony, the FY 1983 ASC's of Portland General Electric and Puget Sound Power & Light were adjusted to exclude power cost adjustments. Meyer, BPA, E-BPA-23S, 2-3. The DSI's and the ICP agree that BPA should assume normal hydro conditions through the rate period for ratesetting purposes and should therefore exclude the power cost adjustments in estimating the FY 1983 ASC of the utilities. Schoenbeck, DSI, E-DS-08, 4; Kuns & Kellerman, ICP, E-IC-01, 4-5.

Evaluation of Positions

As provided in BPA's supplemental testimony, BPA presented revised exchange cost projections which exclude the power cost adjustments to ASC for Portland General Electric and Puget Sound Power & Light. Meyer, BPA, E-BPA-23S, 2-3.

Decision

Although favorable hydroelectric conditions currently exist, and resulting lower resource costs are reflected through power cost adjustments of Portland General Electric and Puget Sound Power & Light, BPA concurs with the DSI's and the ICP that utility ASC projections for FY 1984 and FY 1985 should not incorporate the assumption of continuing favorable hydroelectric conditions. The revised residential exchange cost projections presented in BPA's supplemental testimony and as incorporated in the final proposal, exclude power cost adjustments in the base FY 1983 ASC estimates from which FY 1984 and FY 1985 ASC estimates are projected. FS-BPA-02A, Chapter IV, B-25.

Issue #2

Has BPA incorporated current data in estimating base FY 1983 ASC?

Summary of Positions

In the initial proposal, BPA used ASC data that were available in November 1982. In BPA's supplemental testimony, FY 1983 ASC estimates which were revised to exclude power cost adjustments were also revised to reflect the most current ASC data available in April 1983 with respect to both recently approved ASC as well as pending ASC filings. The DSI's and the ICP in their prefiled testimony suggest that BPA's estimates of FY 1983 ASC's did not reflect the most current data available. Schoenbeck, DSI, E-DS-08, 3; Kuns & Kellerman, ICP, E-IC-01, 6.

While the DSI's forecast, as presented in prefiled testimony, incorporated FY 1983 ASC estimates using relatively current ASC data, the estimates submitted in rebuttal testimony were adjusted to reflect more recent ASC filings data. Schoenbeck, DSI, E-DS-08, 6; Schoenbeck, DSI, E-DS-20R, 2.

However, the ICP's estimates presented in prefiled testimony were derived from ASC filing data and through consultation with each IOU. Kuns & Kellerman, ICP, E-IC-01, Attachment B, 1. These estimates of FY 1983 ASC are outdated in several cases and do not reflect currently available information.

Evaluation of Positions

As provided in BPA's supplemental testimony, BPA presented revised residential exchange cost projections that incorporate the most recent ASC data available as of April 1983. Meyer, BPA, E-BPA-23S, 2-3. The April estimates reflect accurate, consistently derived projections of FY 1983 ASC for each IOU.

Decision

As evidenced in BPA's revised residential exchange cost estimates presented in supplemental testimony, the residential exchange cost projections incorporate base FY 1983 ASC estimates based on ASC data of both approved and pending ASC filings, as of April 1983, derived on a consistent basis. These data were the most current information available at the time the forecast was prepared, Meyer, BPA, E-BPA-23S, 2-3, and are incorporated in the final rate proposal, FS-BPA-02A, Chapter IV, B-25.

b. Calculation of IOU's ASC for FY 1984 and FY 1985

BPA developed a methodology to forecast investor-owned utility ASC by disaggregating and projecting major cost components of each utility's ASC and incorporating numerous forecasting algorithms and assumptions. The major cost components were projected from data obtained from Electric Utilities and Licensee (Class A and B), Annual Report, FERC Form 1, December 1981, for each of the investor-owned utilities. Combined with projections of each utility's system load, resulting ASC estimates were derived and an average annual rate of growth (AARG) in ASC was calculated. This growth rate was applied to BPA's estimate of FY 1983 ASC for each utility to derive the estimated ASC during FY 1984 and FY 1985.

Issue #1

Should BPA's AARG methodology be used to estimate FY 1984 and FY 1985 ASC?

Summary of Positions

In both BPA's initial and supplemental testimony, historical data were obtained for calendar year 1981 from FERC Form 1's. These data were used as a base to project the major individual components of ASC. BPA, E-BPA-2, Attachment 1, Chapter IV, B-14 - B-16. In BPA's initial testimony, the AARG was calculated by utility over the period FY 1983 - FY 1988. The AARG then was applied to each utility's most recent FY 1983 ASC. In supplemental testimony, BPA reevaluated the use of the AARG over a 5-year period and revised projections of IOU residential exchange costs to reflect an AARG calculated over the 2-year period FY 1983 - FY 1985. Meyer, BPA, E-BPA-23S, 3-4.

The DSI's presented IOU residential exchange cost estimates using a methodology similar to BPA's, but did not adopt the AARG methodology. Instead, the DSI's used base FY 1983 ASC data derived from approved and pending ASC filings of each of the IOU's, from which FY 1984 and FY 1985 estimates were projected. Schoenbeck, DSI, E-DS-08, 3, 6. The ICP, using a methodology similar to BPA's, did not adopt the AARG methodology. Rather, the ICP used base FY 1983 ASC data derived from a variety of sources including recent and pending ASC filings and information obtained directly from utility staff of each IOU. Kuns & Kellerman, ICP, E-IC-01, 2-3, 6, Attachment B, 1. The DSI's and ICP use ASC-based data and eliminate use of an AARG from their methodology.

Evaluation of Positions

BPA's methodology is based on the following assumptions. First, the base FY 1983 ASC derived from both approved and pending filings provides a supportable base FY 1983 ASC from which to project ASC's during FY 1984 and FY 1985. Second, the use of the AARG methodology based on historical FERC Form 1 data was adopted by BPA because many of the assumptions used for projecting individual ASC components had to be validated prior to being incorporated into the methodology, and because FERC Form 1 data are available on a historical basis and are a widely recognized and reliable source of information. In contrast, an extensive historical record of ASC filings is not yet available.

Both the DSI's and the ICP dispute the AARG methodology because of the smoothing effect that occurs when discrete cost changes differ between years. The real effects of discrete changes in ASC caused, for instance, by the addition of new large generating units occurring prior to BPA's test year, will tend to be reduced when the AARG is calculated over a period extending beyond the test year. Similarly, an overstatement of test period ASC will occur when discrete, large increases in ASC occur after the test year. This smoothing effect was evident when the AARG was calculated over the period FY 1983 - FY 1988.

In the residential exchange cost estimates presented by BPA in supplemental testimony, the AARG was calculated over FY 1983 - FY 1985 rather than FY 1983 - FY 1988 to eliminate the effects of including costs beyond FY 1985. Meyer, BPA, E-BPA-23S, 3-4. While smoothing effects are still present in the AARG calculated over FY 1983 - FY 1985, the effects have been reduced to take into account the timing uncertainty of utilities' inclusion of ASC costs and varying test years among utilities. Meyer, BPA, E-BPA-23, 10.

Decision

BPA's decision with respect to the use of 1981 FERC Form 1 data and the AARG methodology is delineated in the revised residential exchange cost projections presented as supplemental testimony. BPA continues to support the AARG methodology based on 1981 FERC Form 1 ASC data, but has revised the calculation of the AARG over the period FY 1983 - FY 1985 to alleviate unwarranted smoothing effects created by using an AARG calculated over the period extending beyond FY 1985.

Issue #2

Has BPA accurately accounted for the costs related to new production units?

Summary of Positions

BPA's methodology disaggregates major ASC components, and using a variety of methods, projects each component individually. The impact on the ASC of each IOU due to the addition of new production plant is evaluated by considering new individual production facilities and other costs related to the addition of each plant. In the initial proposal, BPA considered five new major generating units projected to come on line by the end of FY 1988 in estimating IOU residential exchange costs. Costs of major production unit additions were apportioned according to each investor-owned utility's participating ownership share. The capital cost data were incorporated into the AARG methodology according to the month in which the unit was projected to begin commercial operation. Projected increases in new transmission plant were forecast by utility based on a historical average annual rate of growth computed over 1976-1981. More detail on BPA's treatment of specific data is found at E-BPA-2, Chapter IV, B-14 - B-15.

BPA considered and incorporated the following refinements and corrections, and presented revised residential exchange cost estimates in supplemental testimony. Meyer, BPA, E-BPA-23S, 3-7. First, in light of BPA's decision to change the AARG calculation range from FY 1983 - FY 1988 to FY 1983 - FY 1985, major production units projected to become operational after FY 1985 were no longer used in the cost projections. Second, BPA's analysis included additional production units that had been omitted from the cost projections presented in the initial proposal. Third, BPA reevaluated the estimated capital costs of each of the new production units to be included in the analysis, and revised each estimate to correct an arithmetic error that was discovered in the capital cost estimates for Colstrip 3 and 4, and to update the cost estimate for Valmy 2. In addition, cost estimates were obtained for the Fredonia 1 and 2 units and Kettle Falls. Fourth, the calculation of depreciation expense attributable to new facilities was refined to reflect incremental increases in depreciation expense according to the month in which the facility begins commercial operation. Fifth, BPA included a component in the analysis to accommodate incremental increases in fixed operations and maintenance and fuel expenses attributable to the new production units. Meyer, BPA, E-BPA-23S, 3-7.

The DSI's and the ICP agree that only those new production facilities projected to begin commercial operation prior to the test period should be considered in projecting residential exchange costs for the rate period. In addition, both the DSI's and the ICP agree that BPA should include the Fredonia 1 and 2 units as well as Kettle Falls. Schoenbeck, DSI, E-DS-08, 5; Kuns & Kellerman, ICP, E-IC-01, 3-4. The ICP also supported the addition of Hunter Unit 2, owned by Utah Power & Light, in the analysis. The DSI's and the ICP also noted arithmetic errors in BPA's use of estimated capital costs for the Colstrip units. The ICP, in addition, disagreed with BPA's estimated capital costs for Valmy 2. While the DSI's and the ICP each presented capital cost estimates for each of the new production units cited in their testimonies, the DSI estimates differed from the ICP estimates. Schoenbeck, DSI, E-DS-08, 5; Kuns & Kellerman, ICP, E-IC-01, 3-4.

The DSI's in rebuttal testimony stated that "Bonneville's revised [exchange] estimate incorporates both better assumptions and better cost data regarding the rate impact from additional generating units," but also expressed disagreement with BPA's revised capital cost estimate for Colstrip 3. Schoenbeck, DSI, E-DS-20R, 2. The DSI's capital cost estimate for Colstrip 3 differs considerably from BPA's revised Colstrip 3 estimate presented in supplemental testimony. Meyer, BPA, E-BPA-23S, 6. While the DSI's use an estimated production and transmission capital cost for Colstrip 3 of $1,266,360,000, BPA uses an estimate of the production capital cost only of $1,029,871,000. The DSI's estimate of Kettle Falls capital cost was revised to $94,275,000, while BPA estimates a cost of $80,466,000.

The ICP maintains that BPA should consider minor capital additions and replacements to existing plants in addition to including new major production units in projecting capital costs. Kuns & Kellerman, ICP, E-IC-01, 4.

Another objection to BPA's analysis raised by the DSI's was BPA's omission of increases in fixed operations and maintenance expense attributable to the new production units. Schoenbeck, DSI, E-DS-08, 6. Similarly, the ICP cites BPA's exclusion of discrete operations and maintenance expense increases for new production facilities. Kuns & Kellerman, ICP, E-IC-01, 6.

Finally, the ICP disagrees with BPA's algorithm used in estimating depreciation expense related to new production facilities and asserts that depreciation expense is understated due to an imprecise algorithm and lack of negative salvage benefits. Kuns & Kellerman, ICP, E-IC-01, 6.

Evaluation of Positions

In supplemental testimony, BPA incorporated numerous revisions with respect to costs of new production units in projecting residential exchange costs. Some of these revisions were suggested by the DSI's and the ICP. BPA excluded WNP-3 and Wyodak from further consideration in projecting exchange costs for FY 1984 - FY 1985 because neither of these plants are projected to become operational during that time. BPA included Fredonia units 1 and 2, and Kettle Falls in the analysis because they are projected to come on line during FY 1983 and will therefore have an effect during FY 1984 and FY 1985 on the ASC's of the utilities owning these units. BPA analyzed and prepared revised capital cost estimates for Colstrip 3 and 4, and Valmy 2, and prepared capital cost estimates for Fredonia 1 and 2, and Kettle Falls. BPA revised its treatment of depreciation expense attributable to new facilities to reflect increases according to the month in which the facility begins operation to more accurately account for the rate base impact. Finally, BPA included a component to reflect increases in fixed operations and maintenance expense due to the new production units.

The ICP's recommendation to include Hunter 2 was not incorporated in BPA's revised residential exchange estimate because the full capital costs of Hunter 2 are already included in BPA's FY 1983 ASC estimate for Utah Power & Light. Consideration of Hunter 2 as a new production facility would result in double-counting the associated costs and would overstate BPA's residential exchange cost estimates for FY 1984 and FY 1985.

BPA believes that estimated capital costs of new production units presented in supplemental testimony represent reasonable cost estimates. BPA prepared its cost estimates for each of the new production units based on data provided in the PNUCC Thermal Resources Database, December 1982. BPA selected this source because it provides economic and operating data on generating facilities on a consistent basis.

Differing capital cost estimates by BPA, the ICP or DSI's for each of the production units are not improbable given the number of sources from which estimates can be derived. BPA's estimated capital costs of new production units are not based on the same source as was used by the DSI's or the ICP. With the exception of the Colstrip 3 unit, capital costs estimated by the DSI's, the ICP and BPA are within a close range.

BPA believes that the capital cost estimates of Colstrip 3 used by the DSI's in estimating exchange costs is inappropriate and should not be incorporated into BPA's methodology. BPA estimates the capital production costs of Colstrip 3 at $1,029,871,000. The DSI's estimated capital costs of Colstrip 3 are based on cost data presented by Washington Water Power in its current rate case before the Idaho and Washington commissions. Schoenbeck, DSI, E-DS-20R, 2-3, Schedule 2; Schoenbeck, DSI, TR 8338. The DSI Colstrip 3 estimate of $1,266,360,000 includes approximately $1,076,980,000 in production costs and $189,380,000 in transmission plant costs. The DSI's have incorporated this in estimating exchange costs using BPA's methodology, and have inappropriately placed both production and transmission plant costs in

BPA's methodology where only production costs are appropriate. Meyer, BPA, TR 4068-4069; Schoenbeck, DSI, E-DS-20R, 2-3; Schoenbeck, DSI, TR 8339-8340. Since BPA's AARG methodology forecasts increases in transmission plant as a component separate from production plant, use of the DSI's estimate of Colstrip 3 would result in a double-counting of transmission-related costs and would result in an overstatement of projected exchange costs.

In supplemental testimony, BPA revised the calculation used to project depreciation expense related to new production facilities to reflect depreciation expense increases during the month in which each facility begins commercial operation. The ICP implied that BPA has underestimated depreciation expense on new facilities. The ICP, however, has not provided substantive documentation to support this allegation either through their initial testimony or in response to data requests submitted by BPA. Kuns & Kellerman, ICP, E-IC-01, 6, Attachment B, 2-3.

Finally, the ICP's suggestion that BPA include costs related to minor capital additions and replacements to existing plants is inappropriate since BPA does not consider plant retirements in the analysis. Inclusion of minor additions and replacements without inclusion of retirements would represent conflicting assumptions in methodology. BPA, E-BPA-02, Attachment 1, B-14.

Decision

BPA believes that the capital costs of the new production facilities as presented in BPA's supplemental testimony represent reasonable and consistently calculated capital cost estimates for each new facility. With the exception of Colstrip 3, the BPA estimate for each unit is within a reasonable range of those provided by the DSI's and the ICP. With respect to the DSI's estimate of Colstrip 3 as presented in rebuttal testimony, BPA finds that the DSI's estimate is inappropriate and inconsistent with BPA's methodology and would result in an overstatement of FY 1984 and FY 1985 residential exchange costs.

3. Other ASC Components -- AARG Methodology

Issue #1

Should BPA use a fixed rate of return in forecasting each utility's ASC for FY 1984 and FY 1985?

Summary of Positions

In the initial proposal, BPA determined each utility's projected FY 1984 and FY 1985 return on rate base by holding each utility's rate of return constant at the current FY 1983 level derived from approved ASC filings. BPA, E-BPA-2, Attachment 1, Chapter IV, B-15. BPA did not change its use of a constant rate of return in supplemental testimony. The ICP in its prefiled testimony objected to BPA's use of a fixed rate of return in forecasting each utility's ASC during FY 1984 and FY 1985. This argument is based on the assumption that a utility's rate of return will vary over time. Kuns & Kellerman, ICP, E-IC-01, 6.

Evaluation of Positions

The rate of return for each utility was based on approved rates of return derived from ASC filings available in November 1982 when the exchange estimates were prepared for BPA's initial proposal. These rates were held constant over FY 1984 - FY 1985 in the analysis. The ICP disagrees with BPA's use of a fixed rate of return on the basis that new financings, future inflation and scheduled retirement of low interest debt are not reflected through a fixed rate of return assumption. Kuns & Kellerman, ICP, E-IC-01, 6. The ICP, however, in their own estimates of exchange costs, have not incorporated new financings, future inflation and scheduled retirement of low interest debt in its estimates of future rates of return among utilities. Kuns & Kellerman, ICP, E-IC-01, 8, Attachment B.

Decision

While BPA agrees that new financings, future inflation, and retirement of debt are not reflected through a fixed rate of return assumption, the ICP has not presented a methodology which incorporate these factors. Although the ratios and costs of utilities' debt/equity structure may vary from current levels, BPA's use of a fixed rate of return in projecting IOU ASC's and residential exchange costs for FY 1984 and FY 1985 is a reasonable assumption for forecasting these costs.

Issue #2

Are BPA's projections of FY 1984 and FY 1985 ASC end of year estimates?

Summary of Positions

BPA's methodology projects the ASC's for FY 1984 and FY 1985 by disaggregating and projecting major components of ASC to estimate an AARG in ASC for each utility. The AARG is applied to BPA's most recent estimate of each utility's FY 1983 ASC estimate (as of April 1983) to project for each IOU the ASC that will be in effect during FY 1984 and FY 1985. The ICP claims that the ". . . distinction between our model and BPA's estimating technique is important since BPA's ASC estimates represent ASC at the end of the year without regard to the timing of specific cost changes." Kuns & Kellerman, ICP, E-IC-01, 7.

Evaluation of Positions

BPA's algorithms developed as part of the methodology designed to project individual ASC components incorporate numerous assumptions related to the timing of changes in those components. In BPA's revised exchange cost estimates provided in supplemental testimony, BPA corrected, through a minor adjustment, the treatment of depreciation expense associated with new plant. All other ASC components were projected on a consistent basis. The calculated AARG, when applied to BPA's estimate of FY 1983 ASC for each utility, resulted in ASC estimates projected to be in effect during FY 1984 and FY 1985. Meyer, BPA, E-BPA-23S, 4-5.

The ICP's conclusion that their methodology results in average ASC estimates and that BPA's methodology results in end of year ASC estimates is unsupported in their prefiled testimony. The ICP's failed to cite a particular feature of their model that distinguishes theirs from BPA's with regard to this issue.

Decision

The methodology developed by BPA results in reasonable estimates of FY 1984 and FY 1985 ASC for each utility during those years. The ICP's conclusion that BPA's methodology results in end of year ASC estimates is unsupported.

Issue #3

Is BPA's forecast of OY 1985 IOU residential exchange costs reasonable in comparison to the DSI's and the ICP's?

Summary of Positions

BPA's forecast of IOU residential exchange cost estimates as presented in prefiled testimony totalled $899.5 million for OY 1985. Meyer, BPA, E-BPA-23, Attachment 1, 5. In supplemental testimony, BPA presented revised estimates incorporating arithmetic corrections and refinements in the methodology which resulted in an OY 1985 forecast of $942.9 million. Meyer, BPA, E-BPA-23S, Attachment 1, 1. In comparison, the DSI forecast presented in prefiled testimony for OY 1985 was $993.9 million. Schoenbeck, DSI, E-DS-08, Schedule 2. In later rebuttal testimony, the DSI's presented a revised IOU exchange cost forecast of $970.3 million for OY 1985. The DSI's reasserted in their reply brief that BPA's exchange cost estimate was too low, although improved over the initial proposal. Reply Brief, DSI, R-DS-01, 40. Like BPA, the DSI's incorporated over 20 major variables in their revised forecast. Schoenbeck, DSI, TR 6906. In prefiled testimony, the ICP presented an OY 1985 IOU exchange cost forecast of $987.8 million. Kuns & Kellerman, ICP, E-IC-01, Attachment 1, 1.

Evaluation of Positions

In BPA's cross-examination of the DSI's, the DSI's indicated that it would be reasonable to expect different individuals or organizations to use different algorithms to project some of the variables in the IOU exchange cost estimate. Schoenbeck, DSI, TR 6909. BPA notes that the difference between the DSI forecast and BPA's forecast of IOU exchange costs is $27.4 million, or only 2.5 percent of the total projected cost of the residential exchange for OY 1985. This percentage difference is relatively small given the amount of total exchange costs and the uncertainty associated with forecasting these costs. The DSI's also considered a degree of error in the exchange cost forecast of plus or minus 5 to 7 percent to be reasonable and that ". . . 10 percent might be a little high". Schoenbeck, DSI, TR 6909. BPA can assume that the DSI estimate of $970.3 million falls within this acceptable error range of 5 to 7 percent. Given this, BPA's estimate of $942.9 million could have a degree of error as much as 9.6 percent, but more notably, as small as 2.0 percent.

The ICP did not indicate an acceptable degree of error in their exchange cost forecast. Nor was the ICP forecast updated in supplemental or rebuttal testimony. Still, the ICP maintains that their forecast of exchange costs for OY 1985 is sufficiently accurate as originally presented. Reply Brief, PGE, R-GE-01, 7. BPA disagrees with this assertion for two reasons. First, both the DSI's and BPA incorporated average system cost and load data derived subsequent to prefiled testimony to arrive at their respective updated forecasts of exchange costs. A similar effort should have been performed by the ICP for reasons of accuracy and consistency. Second, a revised forecast by the ICP would have been a reasonable undertaking since the ICP forecast is based on fewer major variables than the DSI and BPA forecasts. Therefore, while a comparison between the ICP's forecast and BPA's forecast could be made, such a comparison would be inappropriate as the ICP forecast was not updated.

Decision

BPA agrees that there is a range of acceptable degree of error in forecasting OY 1985 IOU residential exchange costs. Further, it is unlikely that the BPA, DSI and ICP forecasts of exchange costs will be identical given the variability in the number, source, and application of the inputs. Therefore, BPA finds that its IOU residential exchange cost forecast for OY 1985 is reasonable and acceptable. BPA's final forecast of IOU residential exchange costs for OY 1985 is $947.3 million. FS-BPA-02A, Chapter IV, B-6. The difference between BPA's supplemental and final forecasts is due largely to a changed Priority Firm rate assumption.

4. Projection of Public Agency Residential Exchange and ETCA Costs Through FY 1985

BPA analyzed numerous regional public agencies to project public agency residential exchange and ETCA costs for FY 1984 and FY 1985. The following issues were raised with respect to this forecast.

a. Public Agencies Included in BPA's Forecasts

Issue #1

Should Snohomish County PUD be included in BPA's forecast of public agency residential exchange cost projections?

Summary of Positions

In the supplemental testimony, BPA included Snohomish County PUD as a participant in the residential exchange program rather than the ETCA program. Meyer, BPA, E-BPA-23S, 1. BPA included Snohomish in the exchange because it could potentially receive greater benefits under the exchange program than under the ETCA. Meyer, BPA, E-BPA-23S, Attachment 5. Since Snohomish's participation in the exchange would impact BPA's projected revenues and costs, BPA considered it appropriate to include Snohomish in the forecast of public agency exchange costs.

In their direct testimony and during cross-examination, the DSI's also suggested that Snohomish should be made a part of the exchanging public agencies due to the greater net exchange benefits they could receive compared to those under the ETCA. Schoenbeck, DSI, E-DS-08, 10-11. During cross-examiniation, the DSI's witness again stated that BPA should include Snohomish in the exchange for computing the Priority Firm rate during OY 1985. Schoenbeck, DSI, TR 6900. In their reply brief, the DSI's continued to support BPA's decision to include Snohomish as an exchanging utility. Reply Brief, DSI, R-DS-01, 40.

The PPC, on the other hand, contends that BPA should not assume that Snohomish will participate in the exchange (during Period A) for rate setting purposes. Instead, BPA should rely on Snohomish's actual decision on participating in the exchange. Wolverton & O'Meara, PPC, E-PP-02R, 8; Reply Brief, PPC, R-PR-01, 6. This recommendation would give Snohomish the opportunity to consider so-called "feedback effects" (discussed elsewhere) prior to making their decision.

Like the PPC, the WWPUD's claimed that Snohomish should not be treated by BPA as a residential exchanging utility. Hutchinson, et al., WWPUD, E-WW-02R, 11; Opening Brief, WWPUD, E-WW-01, 31-33. However, this recommendation applies to rate Period A since the WWPUD's state that Snohomish may not transfer to the residential exchange from the ETCA before the end of Period A. Hutchinson, et al., WWPUD, E-WW-02R, 12. Both the WWPUD's and PPC note that including Snohomish in the exchange in Periods A and B increases the Priority Firm load, which in turn requires a larger amount of expensive exchange resources to serve that load, thereby increasing the PF-83 rate. Hutchinson, et al., WWPUD, E-WW-02R, 11; Opening Brief, PPC, E-PP-01, 20; Reply Brief, WWPUD, R-WW-01, 20. Finally, the WWPUD's contend that the benefits BPA attributes to Snohomish under the exchange erroneously assumes Snohomish will include the costs of the Sultan Project in its ASC filing commencing July 1, 1983. Reply Brief, WWPUD, R-WW-01, 20-21. The WWPUD's maintain that it is unlikely these costs will be included in Snohomish's retail rates until the Sultan Project is operational, i.e., April 1984. Reply Brief, WWPUD, R-WW-01, 20. The WWPUD's further assert that BPA is unaware of the projected Sultan completion date. Reply Brief, WWPUD, R-WW-01, 20.

Evaluation of Positions

The recommendation of the PPC to exclude Snohomish from BPA's residential exchange cost projections is based on their suggestion that BPA include an ETCA/Exchange Adjustment clause in the final rate proposal. With this clause, BPA could reflect public agency participation in the exchange as it occurs, and adjust the Priority Firm rate accordingly. Wolverton & O'Meara, PPC, E-PP-02R, 8. However, while this argument provides Snohomish with the flexibility to switch from the ETCA to the exchange, it does not acknowledge evidence showing that it would be in Snohomish's economic benefit to be a public exchanging utility. Meyer, BPA, E-BPA-23S, Attachment 5, Chapter IV, B-33 and B-34.

Similarly, despite the WWPUD's contention that BPA should not include Snohomish in the Period A exchange, BPA's forecast shows that participation would result in more net exchange benefits to Snohomish, relative to ETCA benefits, during Period A as well. In addition, it should be noted that Period B is the test period selected in BPA's initial proposal. Since BPA's final rate proposal is based on the same test period, it is prudent for BPA to include Snohomish in the Period B forecast of exchange cost projections for ratemaking purposes.

Furthermore, BPA is aware of Sultan's projected April 1984 operational date, as the record clearly shows. Meyer, BPA, TR 4044. Since any utility's ASC is based on jurisdictional approved rates as provided by the ASC methodology, it is conceivable that the Sultan Project costs could be included in Snohomish's retail rates prior to April 1984. This could be achieved if Snohomish employs a prospective test period in its ratemaking. Therefore, prudent forecasting would require BPA to assume that Snohomish will include cost changes for the Sultan Project in its retail rates before the project becomes operational.

The DSI's acknowledge the greater economic benefit Snohomish could receive under the exchange. However, their testimony suggests that the uncertainty over which public agencies would participate in the exchange could be resolved through a properly designed exchange adjustment clause. Schoenbeck, DSI, E-DS-08, 12-13.

Decision

Snohomish County PUD is projected to receive greater economic benefit by participating in the residential exchange compared to the ETCA in Periods A and B. Further, Snohomish retains flexibility to select either the ETCA or the exchange throughout the entire rate period. BPA believes that Snohomish cannot ignore the considerable projected economic benefit gained from selecting the exchange and, therefore, BPA's final rate proposal includes Snohomish in the forecast of public agency residential exchange costs.

Issue #2

Should BPA revise its forecast of public exchange costs to adjust for public agencies which are no longer members of the Pacific Northwest Generating Company (PNGC)?

Summary of Positions

In prefiled and supplemental testimony, BPA included 17 PNGC members in its forecast of public residential exchange costs for FY 1984 and FY 1985. BPA, E-BPA-2, Attachment 1, Chapter IV, B-11, 28, 35-36; Meyer, BPA, E-BPA-23, Attachment 2, 5-6; Meyer, BPA, E-BPA-23S, Attachment 5. The PNGC, in prefiled testimony, claimed that 4 of the 17 utilities are no longer members of the PNGC and, therefore, should be excluded from the public agency residential exchange. Johnson, PNGC, E-PN-03, 1-2. In addition, the PPC maintained that BPA overforecasted the number of public agencies which should be included in the residential exchange program and suggested that only 13 PNGC members should be included. Wolverton & O'Meara, PPC, E-PP-02R, 9.

Evaluation of Positions

At the time BPA prepared its forecasts of public agency exchange costs, BPA included the 17 PNGC members who had requirements contracts with the PNGC for 10 percent of the output of the Boardman resource. The PNGC later executed new contracts with only 13 of the public agencies. The PPC's rebuttal testimony supports the claim made by the PNGC, and adds that BPA in determining exchange loads should exclude those public agencies no longer being allocated shares of the Boardman resource. Wolverton & O'Meara, PPC, E-PP-02R, 9.

Decision

BPA prepared its forecasts of public agency exchange costs for FY 1984 and FY 1985 based on information that was available when the initial proposal was being prepared. At that time, 17 public agencies were members of the PNGC. BPA concurs with the PNGC and the PPC that public agencies that have withdrawn from the PNGC should not be included in BPA's forecasts of public agency exchange costs and exchange loads. As a result, BPA's final public agency exchange cost forecast includes 13 PNGC members. FS-BPA-01, Chapter IV, B-10.

CHAPTER IV

TIME-DIFFERENTIATED LONG RUN INCREMENTAL COST ANALYSIS

A. Introduction

The Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis is a cost of service analysis depicting the incremental costs BPA incurs on a seasonal, daily, and hourly basis for new generation and transmission load. The analysis identifies the projected costs to be incurred to meet increased customer demand or those costs avoided by customers not demanding additional power. This analysis differs from an embedded cost of service analysis that reflects the book cost BPA is required to recover based on accounting and repayment practices.

The TDLRIC approach applies the principles of marginal cost pricing to electric rates, given the constraints under which utilities must operate. The process involves an analysis of additional facilities expected to meet additional demands. The Least Cost Mix (LCM) Analysis provides a basis for defining the type of incremental generation facilities to be included in the TDLRIC Analysis. The planning horizon used in the analysis allows for the development of long run incremental costs that reflect an optimal mix of generation and transmission capacity.

The TDLRIC Analysis provides the basis for the classification of certain generation costs between capacity and energy in the COSA and certain adjustments in the WPRDS. Application of the illustrative rates developed in the TDLRIC Analysis would provide information to consumers which would enable them to make more efficient consumption and investment decisions based on the costs to society of providing electric power.

B. Theoretical Considerations

Issue #1

Is it appropriate to employ the TDLRIC Analysis in setting rates?

Summary of Positions

BPA believes that rates should reflect marginal cost principles, in order to incorporate the goal of economic efficiency into the price of electricity. This principle is based on the concept that scarcity of resources dictates that choices be made among goods and services, and that these choices should be based on the relative marginal social costs of producing the various goods and services. BPA, E-BPA-06, 1-3.

APAC argues that BPA's objectives are inconsistent with the theoretical requirements for marginal-cost-based rates and that use of marginal-cost-based rates in the absence of these theoretical requirements produces unknown results that may not promote efficiency. Shanker, APAC, E-PA-01, 5; Opening Brief, APAC, B-PA-01, 33, 43. Further, marginal-cost-based rates have been rejected in some jurisdictions including the TVA. Shanker, APAC, E-PA-01, 6, 8, 11, 17; Opening Brief, APAC, B-PA-01, 37. They also argued that marginal cost pricing was rejected during deliberations on the Regional Act. Opening Brief, APAC, B-PA-01, Appendix B. Further, consumers cannot and do not respond to BPA's wholesale rates. Opening Brief, APAC, B-PA-01, Appendix B, 11-12. APAC also argues that BPA has ignored the impact of its rate design on APAC's members, Opening Brief, APAC, B-PA-01, 23-24, that the TDLRIC Analysis results in the "wrong" price signals, Opening Brief, APAC, B-PA-01, 44-49 and Appendix B, that the "wrong" incremental units have been chosen because load forecasts do not incorporate current consumer responses to prices, Opening Brief, APAC, B-PA-01, 45-46, and that the use of the TDLRIC Analysis causes uncertainty and unpredictability. Opening Brief, APAC, B-PA-01, 47-49.

The OPUC argued that marginal costs are relevant to establishing electricity rates, because the cost to society of producing another unit of electricity should be conveyed to consumers, in order to maximize welfare. Oliveira, OPUC, E-OP-01, 5-8.

The DSI's argued that economic theory requires that all prices be set at short-run marginal cost in order to achieve economic efficiency, whereas BPA classifies only two products, capacity and energy, at long run marginal cost. Opening Brief, DSI, B-DS-01, 30.

The PGP argued that there is no theoretical support for LRIC-based pricing of electricity by BPA. Garman, et al., PGP, E-PG-01, 51-52. The PGP argued that since no unique set of prices gives the correct price signal, there can be no clear contribution to economic efficiency from using an LRIC analysis. Opening Brief, PGP, B-PG-01, 22.

The WWPUD's argued that basing rates on LRIC concepts contributes to rate stability and rate continuity. Hutchison, et al., WWPUD, E-WW-01, 13. Also, LRIC studies show how costs will change in the future, thus advising consumers about changes in future electricity prices. Hutchison, et al., WWPUD, E-WW-01, 4. The WWPUD's argued that the long-term benefits of TDLRIC results warrant continued use. Opening Brief, WWPUD, B-WW-01, 15-16. The development and use of the TDLRIC Analysis helps BPA comply with the wholesale rate recommendations of the Regional Plan, helps recover revenues, improves system efficiency, and promotes rate continuity. Opening Brief, WWPUD, B-WW-01, 17-18.

Evaluation of Positions

APAC's position that marginal-cost-based rates depend on the complete fulfillment of a set of theoretical conditions is a misapplication of economic theory. Shanker, APAC, E-PA-01, 5; Opening Brief, APAC, B-PA-01, 33, 43. The APAC argument focuses on the lack of perfect competition in all markets for all goods and services in the U.S., concluding that such a lack undermines

BPA's effort to achieve economic efficiency in pricing its electricity. (See also below, Issue #6.) First, it is completely irrelevant that some prices in the U.S. economy depart from marginal cost, because BPA's rates are of no consequence in many markets, and the income effects of BPA's rates are small in relation to the size of the overall economy. Second, in those markets where BPA electricity does compete with other products, no proof was offered that welfare losses in those markets either exist or are sufficiently large to offset welfare gains from implementing marginal cost principles at BPA. Without such proof, there is no reason to believe that implementing marginal cost principles will lead to inefficient resource allocation.

The APAC argues that marginal-cost-based rates have been rejected in some jurisdictions. However, FERC approved BPA's 1979 rates, which classified costs between capacity and energy in part on LRIC results. BPA, Docket No. EF80-2011 "Order Remanding Rates Without Prejudice," 13 FERC 9161,157 (1980); "Order Confirming and Approving System Rates on a Final Basis," 23 FERC 9161,342 (1983).

Finally, none of the legislative history cited by APAC shows that Congress intended to prohibit the Administrator from using marginal-cost pricing principles to classify costs between capacity and energy. Section 7(e) of the Regional Act provides: "[n]othing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." 16 U.S.C. §839e(e). APAC also ignores legislative history that expressly states that the Administrator is not prohibited from structuring rates designed to give BPA's customers particular price signals: "[s]ection 7(e) clarifies that BPA may continue, as it does under existing law, to charge uniform rates for the sale of electric peaking capacity. The subsection also clarifies that the <u>rate directives</u> contained in this bill <u>only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money</u>. For example, time-of-day rates, seasonal rates, <u>rate structures designed to give BPA customers particular price signals</u>, and other rate forms would be permissible." H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 53 (1980) (Emphasis added).

APAC's opening brief appears to argue that pure marginal- or replacement-cost rates were rejected in deliberations preceding the Regional Act, and that this rejection must carry over to rates that incorporate marginal cost principles in their design, as opposed to rates equal to marginal costs. Opening Brief, APAC, B-PA-01, Appendix B, Section C, 3-7; see also Reply Brief, PP&L, R-PL-01, 36. BPA recognizes that, for example, charging marginal cost might result in overcollection of BPA's revenue requirement. However, BPA does not set the revenue requirement at marginal cost levels. See also Reply Brief, PP&L, R-PL-01, 36. Rates are established at a level sufficient to recover the Administrator's total system costs and to repay the Federal investment. Thus, BPA's rates are based on embedded costs. The use of TDLRIC results to classify costs does not equate with setting rates equal to marginal costs.

A final APAC argument concerns the roles of price signals at the wholesale and retail levels. Opening Brief, APAC, B-PA-01, Appendix B, 11-12. APAC argues that consumers respond to retail prices, not to wholesale prices. This is arguably true, since final consumers do not see wholesale prices. However, BPA is a wholesale utility, and must set prices with regard to wholesale response, not retail response. BPA expects that individual wholesale utilities will respond to BPA's rates in manners appropriate to their respective situations. As BPA is a wholesale utility, BPA cannot expect to achieve retail efficiency in all markets, but must leave those markets largely to the forces operating therein. APAC has not shown that wholesale customers of BPA cannot and do not respond to BPA's prices in a variety of ways. See Taves, BPA, TR 3714.

The DSI argument that economic theory requires that all prices be set at short-run marginal cost in order to achieve economic efficiency is not relevant to BPA's pricing decisions. BPA cannot and does not affect all prices in the economy. This "second best" type of argument is discussed further below, Issue #6, "Do TDLRIC results promote efficiency, either economic or engineering?"

A section of APAC's opening brief, covering pages 42 to 59, contains general arguments concerning possible damage caused by the application of the TDLRIC Analysis. Again, the initial argument is made that "[m]arginal cost pricing priniciples only have validity when certain conditions exist." Opening Brief, APAC, B-PA-01, 43. As discussed elsewhere infra (see below, Theoretical Considerations, Issue #6), this argument is a misapplication of the theory of second best, and is not strictly true as stated. The theory of second best simply cautions against overconfidence in applying marginal cost principles; it does not provide conclusive proof that marginal cost principles will in all circumstances impair economic efficiency.

APAC also argues that BPA has chosen the wrong incremental units, because the load forecasts do not incorporate current consumer responses to prices. Opening Brief, APAC, B-PA-01, 45-46. However, BPA does consider consumer response in its load forecasts. Roberts, BPA, TR 3893; Hoffard, BPA, TR 3897-3898. APAC's argument reflects a misunderstanding of the purpose and mechanics of the TDLRIC Analysis. First, current consumer responses are not directly relevant to the choice of long run incremental units. Second, the incremental units are planned for a time when the system is expected to be in load/resource balance. At that point BPA must look for the least expensive sources of energy and capacity, and those sources are currently projected to be a baseload coal plant and a single-cycle combustion turbine. BPA, E-BPA-06, 12, 14; Emery, BPA, E-BPA-25, 11-13. Third, APAC believes that current price signals will lead to a contradictory situation in which the incremental units chosen today will not be optimal in the future. Opening Brief, APAC, B-PA-01, 46. It is even alleged that the cost ratio will at some point be the opposite of that resulting from the TDLRIC Analysis, namely 17 percent energy and 83 percent capacity. This conclusion is not supported by any evidence, and thus must be regarded as highly speculative.

Although it is true that in some jurisdictions the use of marginal costs in setting rates has not been accepted, many state public utility commissions have accepted various applications of this approach. Sirvaitis, ICP, E-IC-04, 3. In addition, at least two parties specifically supported the use of marginal or incremental cost procedures in setting rates. Hutchison, et al., WWPUD, E-WW-01, 13; Oliveira, OPUC, E-OP-01, 4-9. Also, Snohomish and SCL both use LRIC principles in retail rate design. Saleba, PGP, TR 6414; Opatrny, PGP, TR 6640. The PGP has not provided evidence showing why it is acceptable for SCL, a member of the PGP, to apply LRIC principles at the retail level, Opatrny, PGP, TR 6640, but it is unacceptable for BPA to apply such principles at the wholesale level.

Decision

The results from the TDLRIC Analysis will be used in developing rates. Economic efficiency is an important goal of establishing electricity rates and the use of LRIC principles furthers that goal. Parties rejecting the general use of LRIC principles failed to prove empirically that these principles have damaged BPA's ability to collect necessary revenues and failed to show why LRIC is acceptable in some circumstances but not in others. Parties rejecting such use rely on a misapplication of economic theory, leading to reliance on irrelevant conditions in markets other than those in which BPA operates. Further, these parties relied simply on arguing that welfare losses will inevitably result from the application of TDLRIC principles, without providing substantial evidence identifying and measuring such welfare losses.

The FERC approved BPA's 1979 rates which in part relied on LRIC to classify costs between capacity and energy. BPA has discretion under section 7(e) of the Regional Act in classifying costs, and the legistative history explicitly recognizes price signals as a permissable objective of BPA rate design. BPA is not proposing to set the revenue requirement by marginal cost principles.

Issue #2

Is BPA's application of the National Economic Research Associates (NERA) peak-credit methodology appropriate?

Summary of Positions

The results of BPA's TDLRIC Analysis include the relative LRIC's of generation capacity and energy developed from a modification of NERA's peak-credit methodology. BPA's approach bases the LRIC of capacity and energy on the costs of a combustion turbine and a baseload thermal plant, respectively. BPA, E-BPA-06, 12, 14; Emery, BPA, E-BPA-25, 11-13. The approach considers the fact that each of these generation technologies provides both capacity and energy. A simultaneous equation solution is used to separate the joint products of capacity and energy. BPA, E-BPA-06, 7; Emery, BPA, E-BPA-25, 4-5, 10-11. BPA believes that these specific LRIC's reflect the relative cost of meeting increments of capacity load and energy load in the long run, using available technologies under the assumption that the system is optimally planned. Emery, BPA, E-BPA-25, 5. The NERA peak-credit methodology has been accepted for use in various states and has been under public discussion for some years. Emery, BPA, E-BPA-25, 4. However, modifications were necessary to adapt the methodology to BPA's system. Emery, BPA, E-BPA-25, 4. Based on the results of the TDLRIC Analysis, 83 percent of the total LRIC of generation is energy related and the remaining 17 percent is capacity related. BPA, E-BPA-05, Appendix D, D-3, D-4.

APAC argued that the use of simultaneous equations is improper and unsupported because it assumes that separate units can be designated to supply capacity and energy. Shanker, APAC, E-PA-01, 8-9. Also, APAC argues that the BPA system is not in equilibrium. Opening Brief, APAC, B-PA-01, 34.

The ICP argued that substantial hydro storage makes peak-credit results for LRIC's of capacity and energy appropriate. Sirvaitis, ICP, E-IC-04, 3. PP&L argued that the peak-credit method is accepted by retail regulatory bodies in all Northwest states. Opening Brief, PP&L, B-PL-01, 30.

The PGP argued that there is no justification for BPA's solution to the joint product problem. Garman, et al., PGP, E-PG-01, 53. They argued that the specification of the simultaneous equations is ad hoc and without support in economic theory.

Evaluation of Positions

Tne modified NERA approach to marginal costing was selected by BPA because it reflects the appropriate decision criteria involved in selecting future resources and the method has been used in other electric utility rate cases. Emery, BPA, E-BPA-25, 4-5; Sirvaitis, ICP, E-IC-04, 2-3. The approach selects the least cost methods of providing energy or capacity at the margin in the long run and solves for the cost of capacity and energy separately. BPA, E-BPA-06, 6. Contrary to the APAC position, a utility planner is faced with a choice between different generation technologies that can be used to augment a system's capacity or energy resource capability to meet an anticipated change in load. This choice is based on the economic and operational characteristics of given resources and the types of load that must be met. The planner attempts to meet an increase in capacity and/or energy requirements at least cost and considers the tradeoff between capital and operating costs associated with a given generating resource. BPA, E-BPA-06, Attachment 1, 81-82. The BPA methodology assumes that a single cycle combustion turbine provides the least cost source of capacity and a baseload thermal plant provides energy at least cost. BPA, E-BPA-06, 12, 14; Emery, BPA, E-BPA-25, 11-13. Each of these resources provides the joint products of capacity and energy. BPA, E-BPA-06, 7; Emery, BPA, E-BPA-25, 4-5, 10-11. The problem is how to separate the total cost of a facility into the costs associated with each of the joint products. There is agreement that this problem exists. Garman, et al., PGP, E-PG-01, 53.

The BPA approach is to value the energy produced by the cheapest source of capacity (combustion turbine) at the LRIC of energy and to value the capacity component of the baseload thermal plant at the LRIC of capacity. Since these values all depend on each other, the capacity and energy credits are developed from a simultaneous equation specification. It is clear that when considering marginal generation units, it is appropriate to value their output at the long run incremental cost. This is all the simultaneous equation procedure does. BPA, E-BPA-06, 7; Emery, BPA, E-BPA-25, 4-5, 10-11. To argue that this approach is inappropriate does not consider the intent of the analysis nor the simplicity of the peak credit methodology.

Decision

The purpose of a TDLRIC Analysis is to identify the relative scarcities of capacity and energy in the long run. It is not possible to distinguish the long run from the "margin" noted by a witness for the PGP. Sunday, PGP, TR 6507. APAC failed to show why it is unreasonable to assume that separate units can be designated to supply energy and capacity. Independent sources support the use of separate units, and BPA will continue to make this assumption, which simply recognizes the diurnal variations in loads, and the variety of technologies available to meet those loads.

Parties arguing against the application of the peak-credit method failed to show why such a nationally accepted methodology should not be applied on BPA's system. Even those criticizing this method recognized that it is necessary to quantify and thus separate these joint products. Some rejections were based on the results of the method, not on its logic. The peak-credit results based on the simultaneous equation procedure for the relative incremental costs of capacity and energy are correct and BPA will therefore use the modified peak credit approach.

Issue #3

Should the TDLRIC be based on BPA's actual system and not on a set of hypothetical circumstances?

Summary of Positions

BPA's choice of resources to meet the incremental demand for capacity and energy in the long run is the result of many considerations. Incremental energy load growth is assumed to be met by a baseload coal plant. This coal plant is consistent with BPA's LCM Analysis, which combines current and planned resources with forecasted loads. Emery, BPA, E-BPA-25, 11. A "generic" coal plant is used to approximate as closely as possible the characteristics of an "average" plant unconstrained by site-specific costs. Emery, BPA, E-BPA-25, 13. Incremental capacity load growth is assumed to be met by a single cycle combustion turbine. Costs and technological relations for this plant are based on regional data from the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG). Emery, BPA, E-BPA-25, 13. The determination of costing-pricing periods is based on the current operating characteristics of BPA's system. BPA, E-BPA-06, 8-9.

The DSI's argued that using a hypothetical cost structure yields rates unrelated to the cost of current resources. Drazen, DSI, E-DS-07, 11. The TDLRIC methodology is only appropriate for a hypothetical utility in long-run load/resource balance. Carter, DSI, E-DS-09, 6. The characteristics of BPA's system must be considered in an LRIC analysis. Carter, DSI, E-DS-09, 7, 8.

The PGP argued that BPA does not plan to acquire a base load thermal plant or a simple cycle combustion turbine during "a normal planning horizon" (10 to 15 years), and therefore attempting to measure LRIC based on these units is inappropriate. Garman, et al., PGP, E-PG-01, 55.

APAC argued that there is a lack of certainty regarding the technology which will be available in the future. Opening Brief, APAC, B-PA-01, 36. Also, the TDLRIC is unjustifiably divorced from actual system operations. Opening Brief, APAC, B-PA-01, 38.

Evaluation of Positions

The TDLRIC Analysis does take into account BPA's actual system and the expected operation of and loads on that system over time. While the resources chosen are generic, they represent the least-cost sources of capacity and energy available to BPA on a planning basis. BPA, E-BPA-06, 12, 14; Emery, BPA, E-BPA-25, 11-13. Diurnal and seasonal differentiation is based solely on actual operation of BPA's current system. BPA, E-BPA-06, 20-28; Emery, BPA, E-BPA-25, 22-24. In determining LRIC, both actual operations and expected loads are considered. Emery, BPA, TR 1469. No evidence was cited by the PGP to support the exclusive use of a 10- to 15-year planning horizon. The very purpose of an LRIC study is to analyze conditions at the point of load/resource balance, whenever that occurs. Witness for the PGP agreed that the purpose of marginal cost is to reflect relative scarcities "at the margin". Sunday, PGP, TR 6507. BPA's system is assumed to be optimally configured when the incremental units of the TDLRIC Analysis come on line. Emery, BPA, TR 1464.

Decision

The TDLRIC Analysis identifies the relevant margin, when increments of load (capacity or energy) will cause new resources to be added to the system. As BPA does not predict a deficit until the 1990's at the earliest, it is not possible to use the actual current BPA system alone to project the resources necessary at the margin. BPA has identified the "very long run", a time when the agency will potentially be free of current obligations. Emery, BPA, E-BPA-25, 3. Also, characteristics of BPA's current system are considered when deriving the illustrative rates, and in establishing the seasonal and diurnal differentiation of the illustrative rates. This combination of generic resources and actual operations is the appropriate basis for the TDLRIC Analysis, and makes the best possible use of existing data.

Issue #4

Does BPA's TDLRIC Analysis yield inaccurate or incorrect price signals, because of the projected surplus and other problems?

Summary of Positions

BPA's TDLRIC Analysis yields long run incremental costs of energy and capacity which do not by themselves incorporate analysis of the current surplus, but are purposely based on costs expected to occur after the surplus is over. Emery, BPA, TR 4946-4947. Any price signals based on such LRIC reflect BPA's planning horizon. Current conditions, such as the surplus, were therefore not considered in developing these long run costs.

APAC argued that short run surplus conditions imply a high fixed customer charge and low energy and capacity charges. Opening Brief, APAC, B-PA-01, 35. Further, energy intensive price signals are particularly inappropriate during periods of sustained surplus.

The DSI's argued that BPA's price signals convey information about costs that might be incurred in the future. Drazen, DSI, E-DS-07, 11. Projected costs of future resources are unreliable. Drazen, DSI, E-DS-07, 12. The current surplus renders useless the TDLRIC results based on the assumption of adding resources. Carter, DSI, E-DS-09, 7; Carter, DSI, E-DS-19R, 2. The DSI's argued that using the LRIC results causes the surplus rate to be energy-intensive, thus making it more difficult to sell the surplus and prolonging it. Opening Brief, DSI, B-DS-01, 32-33. Also, price signals based on marginal cost will not work because consumers have shorter time horizons than BPA's long run, because the TDLRIC Analysis uses hypothetical resources that will not actually be used to meet load, and because retail rates do not reflect BPA's wholesale rates. Opening Brief, DSI, B-DS-01, 31.

The PGP argued that the use of TDLRIC Analysis is only appropriate when considering acquisition of resources, which is not planned for the test period due to the surplus. Garman, et al., PGP, E-PG-01, 43, 45; Garman, et al., PGP, E-PG-06R, 26; Opening Brief, PGP, B-PG-01, 22-23.

The OPUC argued that provision of long run price signals is important because decisions are made today which affect the stock of electricity-using durable goods over the long term. Oliveira, OPUC, E-OP-01, 16-17. Decisions are made which will have effects long after the end of the projected surplus, and thus must be informed by the relative scarcities that will exist then.

Evaluation of Positions

The argument by the DSI's that BPA should consider the ultimate impacts of its wholesale rates on retail consumers ignores the fact that BPA is principally a wholesale utility (aside from DSI and Federal agency loads), and that it can therefore hope to influence consumption choices mainly at the wholesale level. Individual utility customers' responses are functions of their individual situations. It is unreasonable to expect that a variety of such situations will lead to identical responses.

The purpose of the illustrative rates is to indicate what marginal costs will be in the future. Emery, BPA, TR 1513. Despite uncertainty regarding future costs, it is nonetheless important to indicate to customers what those costs are, because investment decisions are being made now which will constrain future behavior and influence future consumption. Oliveira, OPUC, E-OP-01, 9. Witness for APAC agreed that the current surplus in capacity would imply a short run marginal cost of zero, but specifically did not advocate using such surplus-caused zero capacity costs in ratemaking. Shanker, APAC, TR 7443, 7444, 7472. Similarly, a potentially near-zero marginal cost of energy today as argued by Shanker, APAC, TR 7473, provides little guidance in setting rates, especially in determining classification for thermal resources.

Perhaps most important, using short run conditions would clearly foster rate instability, an undesirable result. Emery, BPA, TR 4945; Saleba, WWPUD, TR 6418-6419. Optimal system configuration does not depend on the simple existence of a capacity or energy surplus per se, but rather on the sizes of capacity and energy resources relative to respective loads. Sirvaitis, PP&L, TR 7663.

PP&L noted in its reply brief that replacement costs have relevance in pricing decisions, notwithstanding the existence of a surplus, as illustrated by a simple example involving Chevrolets and apple pies. Reply Brief, PP&L, R-PL-01, 30.

Decision

The purpose of BPA's TDLRIC Analysis is to examine costs expected to occur at a point of load/resource balance. Therefore it is not designed to include the current load/resource status of the system, and the price signals resulting from the TDLRIC Analysis alone should not be evaluated in light of current circumstances. Indeed, it was admitted by an APAC witness that current circumstances are of little use in classification, which is the purpose served by the TDLRIC Analysis.

Further, the results of the TDLRIC Analysis show considerable stability over time in the area of classification. Adoption of short run considerations would introduce undesirable instability. BPA therefore uses results of the TDLRIC Analysis in various aspects of its ratemaking.

Issue #5

Should BPA use a generation planning or linear programming approach instead of the current peak-credit methodology?

Summary of Positions

BPA proposed to use a peak-credit methodology. The DSI's argued that BPA should adopt a system-planning method, because it yields both long run and short run results, giving the decisionmaker the flexibility to use the most sensible results. Carter, DSI, E-DS-09, 8, 28-29. The OPUC argued that BPA should adopt a linear programming approach to quantifying long run marginal cost. Oliveira, OPUC, E-OP-01, 10-15. PP&L argued that the peak-credit and systems planning methods produce similar results. Opening Brief, PP&L, B-PL-01, 30.

Evaluation of Positions

BPA is currently unable to implement these approaches because of difficulties encountered in modeling the operation of the hydro system, Emery, BPA, TR 4938, but continues to investigate that possibility. The OPUC results varied according to assumptions regarding water conditions, and it is not clear which assumptions are most reasonable. Hellman, OPUC, E-OP-01, 9-10, 14-15, 20-21. However, witness for the ICP and attorneys for PP&L argued that results for a system-planning method approximate the results of a TDLRIC analysis. Sirvaitis, ICP, E-IC-04, 3, 4; Opening Brief, PP&L, B-PL-01, 30. See also Emery, BPA, E-BPA-25, 5.

Decision

It appears that the results of a system planning approach would not differ significantly from the results of the TDLRIC Analysis. This issue warrants further examination in the future.

Issue #6

Do TDLRIC results promote efficiency, either economic or engineering?

Summary of Positions

BPA's TDLRIC Analysis uses generic resources to meet incremental capacity and energy loads in the long run. These resources are assumed to be added when the BPA system is in an optimal configuration, and represent the least cost means of meeting increments in load. BPA, E-BPA-06, 3. By minimizing cost in a planning sense, engineering efficiency is achieved. The TDLRIC Analysis results promote economic efficiency in the use of resources, because consumers are notified of the relative scarcities of various goods and services. Efficiency is defined in terms of improving social welfare. Emery, BPA, E-BPA-06, 1-2. Engineering efficiency was not discussed in BPA's initial proposal as a concept distinct from economic efficiency.

APAC argues that the theory of second best states that setting one price at marginal cost does not "accurately improve" economic efficiency if some other prices are not set at their respective marginal costs. Shanker, APAC, E-PA-01, 10-11. Marginal cost pricing depends on rigorous conditions to achieve economic efficiency. Opening Brief, APAC, B-PA-01, 33

Appendix C, C2. Also, any prices which cause a decline in system load factor will harm "system efficiency". Shanker, APAC, E-PA-01, 21. Engineering efficiency is measured by system load factor. Opening Brief, APAC, B-PA-01, 55, 56. High load factor customers use the system's resources most efficiently. Opening Brief, APAC, B-PA-01, Appendix D, D1. Engineering efficiency depends on maximizing load factor. Opening Brief, APAC, B-PA-01, Appendix D, D2-D3, D5, D6. Reducing load factor causes a redirection of investment away from "efficient baseload plants to less efficient peaking and intermediate units." Opening Brief, APAC, B-PA-01, 56. There may be a trade-off between economic efficiency and engineering efficiency. Opening Brief, APAC, B-PA-01, 57. BPA relies on economic efficiency to the detriment of engineering efficiency. Efficiency is not conservation, nor a reduction in consumption, but rather using power "in a less wasteful manner" and using "facilities as close to the height of their capability as is appropriate". Opening Brief, APAC, B-PA-01, Appendix E, E1. PURPA requires "optimization of efficiency of use of facilities and resources by electric utilities". Opening Brief, APAC, B-PA-01, Appendix E, E2. Efficient operation is continuous, round-the-clock operation. It is less efficient to serve highly fluctuating demands. Opening Brief, APAC, B-PA-01, Appendix E, E4.

The PGP argues that the efficient allocation of resources means that no other combination of goods and services (produced or distributed) will increase anyone's satisfaction without reducing the satisfaction of someone else. The use of marginal cost to yield efficiency requires perfect competition in all markets, and no externalities. Since these conditions do not exist in the U.S., BPA's attempt to implement marginal cost pricing is "unlikely" to lead to an improvement in economic efficiency. Garman, et al., PGP, E-PG-01, 51; Sunday, PGP, TR 2975-2977.

The OPUC argued that efficiency is achieved when goods are priced at the opportunity cost of the resources used to produce them. Oliveira, OPUC, E-OP-01, 6-7. However, basing rates on long run costs can cause inefficiencies in the short run. Oliveira, OPUC, E-OP-01, 9; Oliveira, OPUC, TR 3191.

The DSI's argued that "none of the requirements for maximizing economic efficiency" is satisfied on the BPA system. Under such conditions, it is not possible to determine whether any pricing methods improve economic efficiency more than others. Opening Brief, DSI, B-DS-01, 30.

Evaluation of Positions

The record is replete with definitions of efficiency, both economic and engineering. It was argued that if you do not have engineering efficiency, you do not have economic efficiency, and that high load factors are associated with economic, not engineering, efficiency. Taves, BPA, TR 3713. Later, Taves, BPA, TR 3731 argued that engineering efficiency is defined in terms of the ratio of inputs to outputs, whereas economic efficiency is defined in terms of the ratio of costs to benefits. BPA witnesses argued that use of the TDLRIC results yields economic efficiency. Emery, BPA, TR 4796-4797; Carr, BPA, TR 5204. Witness for the ICP argued that the Regional Act refers to economic efficiency, and that economic efficiency means setting prices such that the choices made result in the lowest cost to society of producing capacity and energy. Sirvaitis, ICP, TR 7649-7650.

This definitional confusion is not resolved on the record. Regarding engineering or system efficiency, it is difficult to accept arguments by APAC that BPA should seek continuous, round-the-clock operation of its entire system. Most of BPA's resources are hydro, and the generation of electricity from these resources must take into account the fact that loads vary considerably over the year. As a result, BPA may achieve minimum cost in meeting a given year's load (a standard textbook definition of microeconomic efficiency), while experiencing a 60 percent annual load factor. This result is determined by the fact that BPA's loads vary seasonally, with both base loads and peak loads met by hydro resources.

Maximizing load factor as a proxy for efficiency may be appropriate for thermal systems with a mixture of high-running-cost peaking units and low-running-cost base load units. However, it has not been proved why a result for Wisconsin Electric Power Company (see Opening Brief, APAC, B-PA-01, 55 for citation) is necessarily appropriate for BPA. Wisconsin Electric Power (WEP) is predominately a thermal system with very little hydro capacity. "In 1980, WEP generated 56.3 percent of its electricity with coal, 36.7 percent with nuclear fuel, 2.9 percent with natural gas, 2.8 percent with hydro, 1.2 percent with oil, and 0.1 percent with air classified refuse. "Wisconsin Electric Power Company, Initial Decision, 18 FERC ¶63,049, at 65,149. In the case of a power system such as WEP, it is very important to run base-load plants continuously, to spread the high capital costs across large output. Such a conclusion is not immediately relevant for BPA where water used to meet base loads in one month is simply not available in other months.

Continuous operation of a base load thermal plant may be more efficient than fluctuating operation, but the same is not true for either a base load hydro facility or a combustion turbine. In a hydro/thermal system with significant hydro units, occasionally under better than critical water conditions, baseload hydro will be used to displace higher cost baseload thermal facilities. This flexibility is lacking in a thermal-based system. Efficiency of a system can be best understood in terms of operating all plants in that system in a manner that minimizes the cost of meeting load. If BPA dispatches resources to meet load in an economic manner, then it is operating the system efficiently.

APAC's argument that peaking and intermediate units are less efficient than base load units lacks merit. If that were true, one would not expect to see any peaking and intermediate units in an optimally designed system. But even an optimally designed system must meet loads that are not necessarily constant over time, which generally means using base load, intermediate and peaking units. Sirvaitis, PP&L, E-PL-05R, 2-3; Opening Brief, PP&L, B-PL-01, 29; Opening Brief, WWPUD, B-WW-01, 20.

The arguments of "second best" are raised by APAC, DSI, and PGP witnesses, who argue generally that the lack of universal perfect competition and marginal cost pricing bars BPA from acting efficiently in setting rates based on marginal cost. These arguments are based on the observation that although efficiency will be improved in one market by the introduction of marginal cost principles, consumers may respond to the marginal-cost-based prices by shifting consumption into other markets where prices are not equal to their respective marginal costs. In this case, it is possible that efficiency will be reduced in the other markets, and that the net change in overall efficiency will be unknown. The problem is complicated in this instance by the fact that public regulation of energy markets is pervasive, in which case prices may deviate from marginal costs not because of market imperfections, but because of public policy.

It is necessary for proponents of the theory of second best to show (1) that there are markets where BPA electricity competes with other goods that are priced differently from marginal cost for reasons other than deliberate public policy; and (2) that the welfare losses in those markets are at least as large as the welfare gains resulting from the use of marginal cost in pricing BPA's electricity. It is insufficient merely to note that all prices in the U.S. are not equal to marginal cost. Only the prices of those goods competing with BPA electricity are relevant. Furthermore, it is not clear that deliberate public policy has not kept many of those prices different from their respective marginal costs. Natural gas and oil are subject to regulation. Emery, BPA, TR 4872, 4879. This is a statement of public policy, and the resulting prices can be said to result from public policy. As another example, BPA sells electricity to generating public utilities. If those utilities decide to build new sources of power instead of buying more BPA electricity, they will borrow money in capital markets at a lower interest rate than generally available to private utilities, given public policy toward publicly owned utilities. The arguments of second best are not blanket condemnations of marginal cost pricing, but admonitions to consider the effects of that pricing in competing markets. Neither of the two requirements noted above was met with empirical evidence in this proceeding.

Decision

The evidence available indicates that BPA's rates promote both engineering and economic efficiency. Standard economic theory suggests that marginal-cost-pricing improves economic efficiency in the consumption of the good in question. Operation of the system will lead to engineering efficiency, because costs are minimized in a planning sense.

Although the possibility was implicitly raised by various parties that substitution away from BPA power may impair overall efficiency because of other prices not set equal to marginal costs, this concern was not explicitly expressed regarding particular markets. Further, it is clear that many such substitute markets already are affected by public policies that may cause prices to deviate from marginal costs, and thereby affect the quantities consumed.

It is insufficient to depend on a metric such as system load factor to measure the efficiency of BPA's hydro-thermal system. First, system load factor is a result of many influences, many outside BPA's control. (See above, Chapter II, Generic Classification Issues, Issue #2, for a further discussion of load factors.) Second, system load factor is only a proxy for cost when the baseload and peaking units on the system have significantly different capital and running costs. For BPA, this is not true, due to the dominance of hydro resources and the use of hydro for both baseload and peaking operations.

C. Long Run Incremental Cost of Generation

Issue #1

Does BPA use an incorrect capacity factor for the simple cycle combustion turbine (CT)?

Summary of Positions

BPA's initial proposal uses a plant factor of 3.3 percent, which was the weighted average annual capacity factor for 71 oil-fired CT's of 50 to 150 megawatts in 1975. The source of BPA's CT plant factor is the DOE/FERC Hydroelectric Power Evaluation. BPA, E-BPA-06, 13; BPA, E-BPA-06, Attachment 1, 63-64.

A witness for the DSIs argued that BPA's use of an historical national average capacity factor is inappropriate for BPA's system and that the capacity factor for a CT should be determined by comparing the costs of plants which will be operated to meet load growth. That is, a "breakeven analysis" should be performed comparing a CT used for peaking with a baseload coal plant. He suggests a CT capacity factor of 10.5 percent. Carter, DSI, E-DS-09, 9, 16-20; Carter, DSI, TR 6651-6656; Opening Brief, DSI, B-DS-01, 35. Support for a higher CT plant factor than BPA uses comes from the March 1983 PNUCC Northwest Regional Forecast, where existing combustion turbines are shown to have an average capacity factor of 11.3 percent. Carter, DSI, E-DS-19R, 2; Carter, DSI, TR 8124; Opening Brief, DSI, B-DS-01, 35.

Witness for PP&L supports BPA's plant factor of 3.3 percent. Sirvaitis, PP&L, E-PL-05R, 3; Opening Brief, PP&L, B-PL-01, 28-30.

Evaluation of Positions

BPA uses historical weighted average plant factors for CTs across the U.S. as a "best estimate" of a generic CT's operation on BPA's system. The analysis, prepared by FERC, derives a 3.3 percent plant factor by weighting capacity factors for 71 combustion turbine plants between 50 and 150 MW. BPA, E-BPA-06, Attachment 1, 63-64; Emery, E-BPA, BPA-25, 15.

The DSI breakeven analysis is flawed by basing the calculation on a two-resource system. BPA's variety of resources, including intermediate plants, would permit a CT to be operated fewer hours per year. Hutchison, et al., WWPUD, E-WW-02R, 7-8; Sirvaitis, PP&L, E-PL-05R, 1-3; Opening Brief, WWPUD, BWW-01, 20; Opening Brief, PP&L, B-PL-01, 28-30. Indeed, because of the availability (in fact, surplus) of capacity from the BPA hydro system, a combustion turbine would be operated few hours per year. Hutchison, et al., WWPUD, E-WW-02R, 8; Opening Brief, WWPUD, B-WW-01, 20. Thus, the DSI testimony based on a two-resource break-even analysis overstates the CT plant factor.

The DSI witness argued that data from the Northwest Regional Forecast should be used to calculate the capacity factor for BPA's CT. However, the data in this source contain at least two plants inappropriate for BPA's analysis. The DSI witness admitted under cross examination that PGE's Beaver plant is a combined cycle CT, not a simple cycle CT. Carter, DSI, TR 8128. Beaver should thus be removed from the plant factor analysis. Witness Carter also admitted that the Boeing cogeneration facility is operated at an 88 percent plant factor, which is not "normal" for a peaking resource. Carter, DSI, TR 8134-8135. The DSI witness agreed that the Boeing cogeneration facility is operated more hours per year than BPA "could plan" or "should assume" to operate its CT. Carter, DSI, TR 8325-8326. The DSI analysis of plant factor using the Northwest Regional Forecast thus is inaccurate. With these corrections, existing CT's are assumed by the Northwest Regional Forecast to operate at a 4.5 percent plant factor, Reply Brief, DSI, R-DS-01, 44, which supports BPA's lower 3.3 percent plant factor, rather than the DSI's 10.5 percent plant factor. In cross-examination, inclusion of PGE's Bethel plant in the analysis also was questioned because of PGE's peak surplus in the critical period. Carter, DSI, TR 8130-8133. If Bethel is removed, the Northwest Regional Forecast projects a 2.3 percent plant factor for the region's CT's, close to BPA's 3.3 percent. Carter, DSI, TR 8135-8136; Sirvaitis, PP&L, E-PL-05R, 3.

Decision

The historical weighted average capacity factor BPA used for the combustion turbine is a reasonable estimate of the operation of a generic CT on BPA's system. Even though the data are from a 1975 study not restricted to BPA's service territory, the results are more applicable to BPA's system than the theoretical breakeven analysis suggested by the DSI's would be. BPA's massive hydro capability and diverse generation system argue for the use of a relatively low plant factor for future CT's. Proper calculation of a CT capacity factor using data from the March 1983 Northwest Regional Forecast supports BPA's use of a relatively low plant factor. Therefore, BPA will continue to use a 3.3 percent plant factor for the simple cycle combustion turbine.

Issue #2

Has BPA improperly mixed first year capital costs and levelized fuel costs in calculating LRIC?

Summary of Positions

In the initial proposal, BPA used an economic carrying charge to express the recovery of the total initial investment cost plus the time value of money over the life of generation projects. An economic carrying charge increases over the life of each project at the forecasted rate of inflation for the specific project. Thus, the stream of annual payments remains constant over time in real terms. Operation and maintenance expense and fuel costs were levelized in the TDLRIC Analysis in real terms. That is, the stream of operation costs was inflated at the rate specific to that cost and then present valued. This present valued operating cost was then levelized back over the average service life of the asset using an economic carrying charge based on the implicit price deflator. BPA, E-BPA-06, 9-10; BPA, E-BPA-06, Attachment 1, 36-63, and 121-138.

A witness for the DSI's stated that BPA improperly escalated generation costs at several different rates. Combustion turbine and coal plant annual investment costs increase at their respective rates of construction costs; expenses increase at the general rate of inflation. The resulting combustion turbine plant factor, capacity cost, and classification percentages will change each year instead of remaining constant over the life of the plants, as he believes would be appropriate. Another result, according to DSI testimony, is that capacity costs are underestimated. It is argued that the LRIC should be computed using either first year costs for all expenses, or levelized costs which increase at the general rate of inflation. Carter, DSI, E-DS-09, 20-22; Carter, DSI, TR 6673-6674; Opening Brief, DSI, B-DS-01, 36-38; Reply Brief, DSI, R-DS-01, 41-43.

PP&L's reply brief countered DSI criticism and supported BPA's method. The TDLRIC analysis correctly recognizes that capital costs are fixed in the first year and do not change, while variable costs do change over time. Reply Brief, PP&L, R-PL-01, 28.

Evaluation of Positions

BPA's calculation of LRIC treats plant investment costs differently from fuel and operation and maintenance expenses because of the differences in the time pattern of occurrence of these costs. The economic carrying charge measures the change in lifetime costs of bringing a long-lived asset on line in the test year rather than in the future. Emery, BPA, E-BPA-25, 7. The carrying charge applied annually over the service life to the present valued cost of an asset will fully recover the initial cost of the asset and the cost over time of the funds used to purchase it. BPA, E-BPA-06, 9. Thus, the economic carrying charge is calculated using the asset-specific inflation rate. Asset specific inflation rates are used in order to account for any real escalation for those asset types over and above the general inflation rate of the economy. BPA, E-BPA-06, 10. An asset-specific rate does not need to be "escalated" because the present value of the asset's initial cost is fixed in the year it is constructed; the cost stream resulting from application of the economic carrying charge will be constant over time in real terms. Reply Brief, PP&L, R-PL-01, 28. Changes over time in the project's annual carrying charge do not result from real cost changes, but result from inflation causing the costs of competing projects to rise. BPA, E-BPA-06, 9.

Expenses for fuel and operation and maintenance occur throughout a project's lifetime. Thus, a levelized stream of these costs must account for inflation in the general economy and cost-specific escalation rates over the life of the facility. Using a first year cost estimate for these expenses will not reflect how costs change in real terms over time. Reply Brief, PP&L, R-PL-01, 28.

Decision

BPA does not agree with the DSI assertion that BPA's LRIC is calculated improperly because of its lack of uniform treatment of capital costs and fuel and operation and maintenance expenses. BPA uses different treatments for these types of costs to reflect their different patterns of occurrence over time. The fact that the classification percentages derived from the LRIC may change from year to year is insufficient reason to change the treatment of these costs. Therefore, BPA will continue its current treatment of capital costs and operation and maintenance expenses.

Issue #3

Were forced outage reserve requirements for the combustion turbine (CT) and coal plants incorrectly assigned and applied?

Summary of Positions

BPA's used a 13.88 percent capacity reserve factor for calculating the LRIC of generation capacity. It was calculated by weighting peaking reserves for Federal hydro and Federal thermal resources expected to come on line through the year 1991. The capacity reserve factor was applied to the cost c the CT and thus used to value the capacity component of the base load coal plant. BPA, E-BPA-06, Attachment 1, 65-68; Emery, BPA, TR 4810-4814.

WWPUD's testimony suggests that BPA should use a 5 percent reserve requirement for the CT, which represents the forced outage rate for peaking facilities. They state that combustion turbines have relatively lower unit reserve requirements; therefore, BPA has overstated the cost of peaking facilities. The WWPUD's believe that BPA should use a 15 percent reserve requirement for the coal plant, to reflect the larger reserve requirements needed by the relatively larger baseload thermal plants. The 15 percent should be applied only to the fixed costs of the coal plant, to reflect cost causation. Hutchison, et al., WWPUD, E-WW-01, 5-8; Saleba, WWPUD, TR 6455-6460; Opening Brief, WWPUD, B-WW-01, 21.

A witness for the DSI's, in support of BPA's position, points out that capacity reserves must reflect the contribution of both peaking (CT) plants and baseload (coal) plants to serving peak loads. Carter, DSI, E-DS-19R, 6-7; Opening Brief, DSI, B-DS-01, 41-42.

Evaluation of Positions

The capacity reserve factor adjusts incremental capacity costs to reflect the fact that any resource addition to the Federal system requires the addition of capacity reserves. Emery, BPA, E-BPA-25, 14. The TDLRIC Analysis' capacity reserve factor is based on forced outage reserve levels and is representative of a reserve needed for a typical addition of generic capacity. BPA, E-BPA-06, 13. BPA's LRIC of capacity thus reflects the weighted average capacity reserves of all peaking resources. Emery, BPA, E-BPA-25, 14-15. As witness for the DSIs points out, sufficient reserves for peak periods must come from baseload as well as peaking plants, because both contribute to serving peak loads. Therefore, reserves for all resources should be included when calculating the LRIC of capacity. Opening Brief, DSI, B-DS-01, 42.

The WWPUD's suggestion to adjust the LRIC of energy for the 15 percent forced outage rate for the coal plant is also incorrect. Opening Brief, DSI, B-DS-01, 42. BPA's peak credit method recognizes the need for reserves for the baseload coal plant. The 75 percent capacity factor assumed for the baseload coal plant includes an adjustment for forced outages. Opening Brief, DSI, B-DS-01, 42. To add 15 percent to the capital cost of the baseload coal plant would double count reserve requirements. Carter, DSI, E-DS-19R, 7.

Decision

By applying a weighted average capacity reserve factor to the calculation of the LRIC of generation capacity, and then crediting this amount to the cost of the generic baseload coal plant, the capacity reserve requirements of the generic coal plant are taken into account. Thus, it is unnecessary to apply separately the 15 percent capacity reserve requirement. BPA believes that it has correctly determined capacity reserve requirements for use in calculating the LRIC. A weighted average reserve requirement correctly values the added reserves a typical new resource would require and the approach will continue to be used.

Issue #4

Does BPA use too high a heat rate for the combustion turbine (CT)?

Summary of Positions

BPA's initial proposal uses a heat rate of 13,800 BTU/kWh from the EPRI Technical Assessment Guide (TAG). This is a national average annual heat rate for a conventional combustion turbine. BPA, E-BPA-06, Attachment 1, 46, 51.

A witness for the ICP and PP&L believes that BPA should use data provided in the PNUCC Thermal Resources Database to determine the proper heat rate for a combustion turbine in the Northwest, rather than the generic heat rate from the EPRI TAG. An average heat rate for recently installed gas-fired turbines in the Northwest is 10,600 BTU/kWh. Sirvaitis, ICP, E-IC-04, 4-5; Opening Brief, PP&L, B-PL-01, 28; Reply Brief, PP&L, R-PL-01, 7-8.

A DSI witness countered the ICP position by stating that the thermal efficiency of a CT increases (heat rate decreases) as the plant is more fully loaded. He claimed that heat rate of 10,600 BTU/kWh reflects a plant loaded to 84 percent of capacity, which is inconsistent with BPA's assumed low plant factor. Carter, DSI, E-DS-19R, 5; Opening Brief, DSI, B-DS-01, 41.

Evaluation of Positions

BPA's use of the heat rate presented in the EPRI TAG is consistent with BPA's use of other generic data for the combustion turbine from the same source. Emery, E-BPA, BPA-25, 15. BPA does adjust its capital and operating costs for regional differences, as recommended by the EPRI TAG. BPA, E-BPA-06, Attachment 1, 36. EPRI does not suggest regional adjustment of heat rate, however. BPA, E-BPA-06, Attachment 1, 50. The ICP position depends on heat rates for only four CT's, which BPA believes is too small a sample to be significant. EPRI data are reliable and allow BPA to maintain consistency in its analysis of generic CT's. Emery, BPA, E-BPA-25, 15.

Although the DSI testimony backed BPA's position, as pointed out in cross-examination and in the PP&L opening brief, heat rate and plant factor are not correlated. Carter, DSI, TR 8143-8145; Opening Brief, PP&L, B-PL-01, 29.

Decision

BPA remains unconvinced that plant heat rates are region-specific. Use of a combustion turbine heat rate from the EPRI TAG in the TDLRIC Analysis is reasonable and consistent with the use of EPRI data elsewhere in the TDLRIC Analysis to calculate costs of a generic CT. Since EPRI does not suggest regional heat rates, BPA's use of a generic heat rate is appropriate. The generic heat rate is also consistent with the use of other generic data. Therefore, BPA will continue to use EPRI's recommended heat rate of 13,800 BTU/kWh.

D. Long Run Incremental Cost of Transmission

Issue #1

Should the cost of generation-integration be included in the LRIC calculations?

Summary of Positions

The long run incremental cost of generation-integration was not included in the 1983 initial TDLRIC Analysis due to the lack of generation-integration investment data. The only generation-integration investment during the transmission planning horizon was a small amount associated with projects which are essentially complete, which was not felt to be representative of incremental generation-integration costs. Emery, BPA, E-BPA-25, 17. BPA's TDLRIC Analysis rebuttal testimony presented an analysis of forward-looking generic generation-integration costs. Emery, BPA, E-BPA-44R. The WWPUD's pointed out that generation-integration investment is necessary to provide power and thus should be included in the TDLRIC Analysis. Marginal costs of generation-integration facilities should be approximated based on escalated historical cost data and added to the overall power supply marginal cost calculation. Hutchison, et al., WWPUD, E-WW-01, 8.

Evaluation of Positions

The initial BPA position was based on a lack of generation-integration investment data consistent with the other transmission data used in the TDLRIC Analysis. The WWPUD's pointed out that a reasonable proxy for generation-integration costs could be constructed with historical generation-integration investment data. This approach could be used, but the resulting investment levels are sensitive to the location and type of generating facilities being integrated. This sensitivity could lead to incremental generation-integration costs not being representative of a generic generation-integration cost. BPA's rebuttal testimony presented an analysis of a generic set of facilities required to integrate planned resources, which produced generic generation-integration costs.

Decision

BPA agrees that incremental costs of generation-integration should be included in the TDLRIC Analysis. BPA's generic methodology for calculating the LRIC of generation-integration presented in BPA rebuttal testimony, Emery, BPA, E-BPA-44R, is used in the final 1983 TDLRIC Analysis.

E. Selection of Costing/Pricing Periods

Issue #1

Is the 1957-58 water year the appropriate water year to use for determining probability of negative margins?

Summary of Positions

BPA used the 1957-58 water year in the Coordination Agreement Reserve Program (CARP) to develop probability of negative margin (PONM) statistics. A theoretically more correct prospective PONM for the Federal system would be based on an analysis of each of the 40 water years. This requires that the CARP be run 40 times for each prospective year. The resulting PONM's for each of the 40 water years would be used to develop a probability distribution of PONM's for each future year. The mean value of this probability distribution would be selected as measuring the likelihood of load exceeding capability in a given year. As an approximation, the 1957-1958 water year is selected as an average capacity year for the Federal system and PONM's are developed that approximate the mean value of 40 water years. BPA, E-BPA-06, 23; BPA, E-BPA-06, Attachment 1, 209-213. The ICP questioned the use of the 1957-58 water year as typical because April peak capability during that year was very low relative to the 40 year average for April. Opening Brief, PP&L, B-PL-01, 52-53. Their testimony introduced comparisons of Federal hydro peaking capabilities under various water conditions and suggested that a critical period average was a more appropriate measure of Federal hydro peaking capabilities for use in developing PONM statistics. Sirvaitis, ICP, E-IC-04, 22.

Evaluation of Positions

BPA has chosen the 1957-58 water year as a typical water year that exhibits minimal deviation from the mean water conditions based on 40 historical water years. Witness for the ICP agreed in cross-examination that all months of the 1957-58 water year, except for the months of March, April, and May, exhibit hydro peak capability levels closer to the 40-year average than does the critical period average recommended by the ICP. Sirvaitis, ICP, TR 7607; E-BPA-50. In addition, the use of a water value based on the monthly average of various years for estimating peaking capability ignores the close relationship between the monthly water flows and the reservoir storage resulting from any given water year. It is also the case that BPA plans for peaking capability by assuming average water availability, which suggests that water flows over the critical period are not appropriate for use in the PONM analysis.

Decision

To plan for capacity needs, BPA selects a single water year which closely approximates average water conditions. The use of an average water year does not reflect the flows between months and the various effects of reservoir storage that occur in any single water year. Although 3 months in the 1957-5 water year differ more from the 40-year average than the corresponding month in the critical period average, BPA has shown, and the ICP witness has agreed, that nine months in the 1957-58 water year are closer to the 40-year average than the corresponding months in the critical period average. By this measure, the 1957-58 water year can be judged "closer" to the 40-year average, which is the goal of this analysis. Therefore, BPA will continue to use 1957-58 water conditions in the PONM analysis.

Issue #2

Is the load addition made in calculating the PONM statistics inappropriate, and should the PONM's be levelized over the year?

Summary of Positions

The Coordination Agreement Reserve Program (CARP) used to develop the PONM's in the TDLRIC Analysis measures the probability that the system peak load will exceed the available peaking generation as required by the Pacific Northwest Coordination Agreement. According to the Agreement, the firm peak load carrying capability (FPLCC) of the coordinated system is the forecasted load, equally greater or less in all months than that submitted, which can be served by the firm peak resources of the coordinated system, with a probability of load loss equivalent to 1 day in 20 years. A loss of load probability of 1 day in 20 years is the same as an annual probability of load loss of 0.05. When estimating the FPLCC of the system at a probability of load loss of 0.05, the CARP, as indicated in the Agreement, increases or decreases the forecasted load by a uniform amount in all months. The CARP estimates monthly PONM's that vary between the months and support the determination of seasonal capacity periods over the long term.

The WWPUD's argued that the absolute level of probability of negative margins is effectively zero for all five of the operating years reviewed. They argued that the increase in loads to produce an annual PONM value of 0.05 is not appropriate and there should be no seasonal differentiation of capacity costs. Hutchison, et al., WWPUD, E-WW-01, 9-11; Opening Brief, WWPUD, B-WW-01, 23-24; Reply Brief, WWPUD, R-WW-01, 22-24.

Evaluation of Positions

The addition of peak load in the CARP is necessary to determine the firm peak load-carrying capability of the system while meeting the reliability criterion of an outage one day in 20-years, set forth by the Pacific Northwest Coordination Agreement. The load addition is constant on a monthly basis but varies by year according to the load-resource relationship in that year. The load addition is for instantaneous peak, not sustained peak. The amount of sustained peak load added to achieve the desired outage level would be significantly below the amount of instantaneous peak load added.

The WWPUD's argued that there are no significant seasonal relationships in capacity costs since loads must be increased by such a significant amount before PONM is achieved. However, by adding a constant load over the year, BPA maintains the relative PONM by month since this addition does not change the load shape. The relative values of PONM are important in selecting seasonal capacity periods; the differences among the months signal that loads and resources do vary on a monthly basis. Consequently, the amount of peak resources needed to maintain the specified level of reliability varies over the year.

The WWPUD's argued that the monthly PONM's produced by the CARP for its system reliability analysis provide a reasonable proxy for determining when the system is reaching its capacity constraint. However, they took issue with the additional increase of capacity load to create a system capacity constraint. Reply Brief, WWPUD, R-WW-01, 23. BPA uses the results of the system reliability analysis to establish capacity costing periods and uses the capacity allocation cost factors for seasonal differentiation. There is a definite cost to BPA incurred in maintaining a specified level of reliability. The costs of that maintenance differ by month, and these cost differences serve as a basis for differential capacity costs by season.

While it may be desirable to levelize the risk of outage over the year, BPA cannot levelize PONM's entirely. Thermal and hydro resource maintenance schedules lack the complete flexibility needed to ensure that all maintenance is performed during months of low risk of outage. Factors such as flood control restrictions, rule curves, fish and wildlife water budget, bank stabilization, and irrigation withdrawals inhibit the flexibility of the hydro system. Carter, DSI, E-DS-19R, 8. This flexibility is needed to ensure that capability can be shifted to the periods of highest PONM's. Thus, a number of factors prohibit BPA from levelizing the risk of outage to the point where no seasonal capacity differentiation exists.

Decision

BPA has determined that the Coordination Agreement Reserve Program is the appropriate study to signal BPA as to the operational needs of the system. This study tells BPA the amount of peak resources needed to maintain the level of reliability specified by the Pacific Northwest Coordination Agreement. The load additions made in the study do not alter the monthly load shapes and hence do not change the relative PONM's. Institutional and operational constraints do not allow BPA to levelize the PONM's throughout the year. BPA is warranted in making load additions which do not change the relative PONM's, but do bring the absolute PONM's to the specified level of reliability. Thus, the load addition made in calculating the PONM statistics is appropriate and there is seasonal differentiation evidenced by the PONM statistics.

F. Allocation of Costs to Periods

Issue #1

How should BPA handle May energy costs?

Summary of Positions

BPA has proposed that the water budget provided for in the Columbia Basin Fish and Wildlife Program will cause a substantial increase in the availability of energy under critical water conditions during the month of May. An increase in energy demand during the month of May would not require BPA to obtain additional baseload thermal capacity. Thus, the seasonal period for incremental energy generation is all months of the year except May and zero long run incremental costs are assigned to May. Emery, BPA, E-BPA-25, 24.

The ICP argued that the opportunity cost or value of the alternative use of the May surplus energy should be taken into consideration. The ICP argued that thermal plants operating in the region during May could have their fuel and operating expenses reduced by the availability of this surplus energy. The ICP proposes that BPA undertake an analysis of long run opportunity cost or assume energy-related costs for May are 20 percent less than the cost in mills per kWh for other months. Sirvaitis, ICP, E-IC-4 25-27; Opening Brief, PP&L, B-PL-01, 53-55. The 20 percent figure recommended by the ICP was not based on any specific study, but on a rule of thumb or conservative estimate. Sirvaitis, ICP, TR 7646.

WWPUD's proposed that the May energy should be assigned a portion of the cost of thermal generated energy because water thereby is able to be stored in reservoirs for use during May; i.e., costs should be assigned to time of energy use rather than time of energy production. Hutchison, et al., WWPUD, E-WW-01, 11-12; Saleba, WWPUD, TR 6383; Opening Brief, WWPUD, B-WW-01, 21-23. They also argued that a zero charge for energy usage in May would cause large amounts of load to be shifted from other months to May to take advantage of the lower energy costs. They proposed that shifts in load could quickly use up any surplus energy associated with May. Hutchison, et al., WWPUD, E-WW-02R, 9-10.

Evaluation of Positions

In the short run, BPA markets available energy by considering such factors as the size of the various markets and the revenues to be received. In the long run, BPA plans to acquire sufficient resources to meet firm load reliably under critical water conditions. Resources are not planned to serve other markets in the long term. The TDLRIC Analysis measures the incremental cost to BPA of the resources used to meet an increase in firm load under critical water conditions. The effect of the water budget is to create new planning criteria that provide for a large amount of potential energy during the month of May under critical water conditions. The energy would theoretically be used on a planning basis to serve firm energy load before it is used in displacement or nonfirm markets. In the long run, the additional cost to BPA to meet an increment of energy load during May is zero. A zero LRIC of energy during May indicates that a surplus of resources exists and that load should be shifted to May until the surplus is absorbed.

Furthermore, it is not clear that BPA has a legal option to shift water out of May into other months, notwithstanding water conditions. Dean, BPA, TR 3576-3577. There are many constraints on the BPA system. Dean, BPA, TR 5740, 5742, 5756. The water budget is another binding constraint, one which reduces annual firm energy and increases nonfirm. Dean, BPA, TR 3573. The ICP and WWPUD's arguments are based on short run considerations. In the long run, there is no opportunity cost to the water budget because BPA has no choice but to store water for use during the spring. The TDLRIC Analysis attempts to send correct long run price signals. Assigning zero costs to May in the TDLRIC Analysis achieves this purpose.

Decision

It is economically efficient to assign zero as the long run incremental cost of May firm energy. Due to the expected long-term nature of the water budget, BPA will not have to plan for additional baseload thermal capability for that month to meet an incremental increase in load. A zero price signal for that month is theoretically appropriate to allocate scarce resources efficiently over the year. Also, the argument that BPA should value the LRIC of May firm energy at an "opportunity cost" ignores the fact that BPA does not have the opportunity to shift water from May to other months. The concept of opportunity cost assumes opportunities, i.e., choices. The water budget eliminates choice, and thus renders invalid calculations based on choice.

CHAPTER V

COST OF SERVICE ANALYSIS

A. Introduction

The purpose of the Cost of Service Analysis (COSA) is to assign responsibility to each of BPA's customer classes for costs incurred in providing service to those customers. The COSA also serves as an aid in determining the adequacy of rates currently in effect, and provides a basis for designing new rates that will recover from each customer class the costs assigned to them. The analysis performed in the COSA consists of five basic steps:

1. Functionalization apportions costs between the functions of generation and transmission;
2. Segmentation divides costs between the segments of the FCRTS;
3. Classification divides generation and transmission costs between capacity and energy;
4. Seasonal differentiation apportions energy and capacity costs to winter and summer; and
5. Allocation apportions costs to rate classes.

B. Functionalization, Segmentation, and Classification

There were no significant issues raised concerning functionalization and segmentation. However, there are various issues concerning COSA classification evaluated in Chapter II, Preliminary Issues.

C. Seasonal Differentiation

1. Energy

Issue #1

Has BPA appropriately reflected the costs of energy during the month of May in the COSA?

Summary of Positions

In the initial proposal the COSA treated the costs of energy during the month of May in a manner that reflected the results of BPA's TDLRIC Analysis. The TDLRIC Analysis concludes that the seasonal period for incremental energy generation is all months of the year except May. BPA, E-BPA-6, 24. The COSA therefore assigns no costs to firm energy produced during the month of May. All costs associated with generation of firm energy during the month of May are reassigned in the COSA to the other 11 months of the year. BPA, E-BPA-6, Attachment 1, 231. After this reassignment of May energy costs to all other months, all costs incurred during each month of the year, including zero costs in May, are grouped into summer and winter seasons. The relative distribution of those costs by season reflects the seasonal differentiation of energy costs in the COSA. BPA, E-BPA-5, F-6. Based on withdrawals of energy from storage indicated by the operations of the hydro system, April through August is chosen as the summer season and September through March is the winter season. BPA, E-BPA-5, F-5.

The ICP contends that BPA's approach does not accomplish the desired objective of reflecting the TDLRIC Analysis. They assert that in order to reflect the TDLRIC findings, BPA would have to show no energy costs for the month of May, and uniformly higher energy costs in the other 11 months. They claim that the COSA does not reflect an absence of May energy costs. In the COSA, the reallocation of May costs results in allocated energy costs for May of 10.52 mills per kWh, substantially reduced unit energy costs in the summer months, and substantially higher unit energy costs in the winter months than otherwise would be determined. The ICP argues that BPA has corrected a situation in which one of 12 months (May) was priced contrary to cost by shifting costs in a manner that prices all 12 months incorrectly. They recommend that if BPA desires to reduce May energy charges to reflect all or part of the lower May costs, lost revenues should be spread uniformly over all other kilowatthours, maintaining a cost-based seasonal differential of 0.37 mills per kWh, which they have calculated as the rate differential between winter and summer seasons. Sirvaitis, ICP, E-IC-04, 23-28.

The WWPUD's claim that BPA has taken the energy costs associated with May kilowatthours and spread them to all remaining months. They assert that this procedure takes summer related energy costs and allocates a portion of them to the winter period. They recommend that the procedure used in BPA's 1982 final rate proposal to determine seasonal energy costs, based on storage withdrawals, is appropriate. Hutchison, et al., WWPUD, E-WW-01, 33-34.

Evaluation of Positions

The method used by BPA in the COSA for assigning seasonal energy costs to winter and summer periods treats May as a summer month, not as a separate season unto itself. However, the method does reflect the results of the TDLRIC Analysis which indicates that the long run incremental energy costs associated with May are equal to zero. Carr, BPA, TR 4969. The argument made by the WWPUD's that BPA has allocated summer energy costs to the winter period is not entirely accurate. BPA has reallocated some of the energy costs associated with May into the summer season. BPA, E-BPA-5, Attachment 1, 231. Only a portion of the costs of May energy were assigned to the winter season.

The ICP analysis and WWPUD's testimony argue that the cost allocation implicit in the COSA yields a seasonal energy differential greater than that implicit in the TDLRIC Analysis. Sirvaitis, ICP, E-IC-01, 26; Hutchison, et al., WWPUD, E-WW-01, 33 However, the ICP position ignores the fact that the COSA must combine TDLRIC results with other analyses. These other analyses currently identify a summer season for the BPA system which includes April through August. This summer season is a function of relatively small amounts of generation from storage. BPA, E-BPA-5, F-2. The relatively larger seasonal energy differential noted by the ICP is simply the result of combining two separate analyses, BPA's COSA and TDLRIC. That there are differences in the final unit costs is not by itself sufficient reason to reject such a combination. The WWPUD's argument ignores the fact that the TDLRIC Analysis does not find a distinction between summer and winter, but between "May" and "not May", so that it cannot be said that using the TDLRIC results moves "summer" costs into the "winter", but rather May costs are moved out of May. Cost allocations in the COSA are made on the basis of load distributions by seasons. BPA, E-BPA-5, 40-46. The costing of resources during the month of May has no quantifiable effect on loads anticipated during the month of May. BPA, E-BPA-03, 15-19; Hoffard, BPA, TR 3888-3905. Loads during the month of May are allocated costs which reflect the seasonal differentiation of resource costs between winter and summer energy periods. BPA, E-BPA-5, F-6. May loads are allocated costs of the summer energy period because May is a summer month. No attempt is made by BPA in the COSA or elsewhere to treat May as a separate season, which would result in the allocation of no costs to loads during the month of May, and would require sales of May energy at no charge.

The ICP argument that BPA has corrected a situation where 1 month (May) is priced contrary to cost by pricing all other months incorrectly confuses the seasonal differentiation of resource costs with BPA's process for allocating those costs to loads. While long run resource costs during the month of May are assumed to be zero and redistributed to the other eleven months, May loads are considered to be summer energy loads and are allocated the seasonally differentiated summer energy costs. BPA, E-BPA-5, 40-41. The confusion between seasonal differentiation of costs and allocation of costs is evident in PP&L's statement that BPA either should establish a May price equal to what it finds May costs to be, or should not make any May adjustment. Opening Brief, PP&L, B-PL-01, 56. This assertion presupposes that May should be treated as a separate season.

The method used in the COSA for selecting costing periods relies on an examination of energy generated from withdrawals of stored water in the hydro system to serve loads. BPA, E-BPA-5, F-5. This method examines information which would allow the selection of a peak period broad enough to allow for shifts in load, and including months displaying similar characteristics. From examination of withdrawals of stored hydro energy, September through March is chosen as the peak winter energy season. The period April through August is chosen as the offpeak summer energy season. BPA, E-BPA-5, F-2. The TDLRIC, on the other hand, selects costing periods based on causation for incurrence of long run incremental costs. In the TDLRIC, the offpeak summer energy season selected is the month of May alone; all other months are selected as the peak season. BPA, E-BPA-6, 24. Because May is already included in the offpeak summer season in the COSA, no adjustment is made to reflect the TDLRIC results in the selection of costing periods. BPA, E-BPA-5, F-2.

The COSA does however adjust costs assigned to the selected peak and offpeak energy periods to reflect the TDLRIC costing of May energy by assigning all costs attributable to May energy to the peak energy season selected by the TDLRIC (all months except May). This results in a reassignment of May energy costs to all other months (peak summer months and offpeak winter months) in the COSA. BPA, E-BPA-5, Attachment 1, 231.

After seasonal periods have been selected and costs assigned to those periods, the COSA allocates seasonal costs to loads. Energy loads during the month of May are considered summer offpeak loads and are allocated summer energy costs. The rate differential between summer and winter energy results not from an incorrect 'pricing' of energy in all twelve months of the test period, but from an incorporation of TDLRIC costing of May energy in the COSA and the inclusion of May in the COSA offpeak energy season, rather than as a separate season. Seasonal energy costs are therefore correctly calculated in the COSA and such seasonal costs are correctly allocated to winter and summer energy loads. It is necessary to reconcile the long run signal from the TDLRIC Analysis with prudent current ratemaking procedures in the COSA. Although it may be desirable to encourage load growth in May, it is not administratively feasible to have a special energy season for 1 month. Furthermore, a period as short as 1 month could easily encourage inappropriate short-term load shifting that would cause operational problems. The long run price signal must be tempered by other considerations, and May thus must be treated for ratemaking as a part of either summer or winter. May bears more similarity on BPA's system to summer months than to winter months. Reply Brief, NIU, R-NI-01, 27. The costs BPA incurs to meet May loads are therefore more like those of other summer months than other winter months.

Decision

Because of the planned abundance of firm energy in excess of projected firm loads during the month of May, load growth during the month of May will not cause the incurrence of long run incremental costs. BPA, E-BPA-6, 24. However, it is not a reasonable approach for BPA to distribute electric power during the month of May at no charge. May is a summer month on BPA's system, and sales of power during May should be made in accordance with BPA's summer energy rate schedules. BPA believes that the redistribution of May energy costs to all other months is correct and the COSA has correctly calculated the seasonal assignment of costs, while reflecting no long run incremental costs attributable to May energy loads. The resulting differential between winter and summer rates accurately reflects this redistribution of costs. BPA's treatment of May energy costs reflects cost causation and is, therefore, appropriate in both the seasonal differentiation of costs and the development of winter and summer rates.

Issue #2

How should BPA seasonally differentiate FBS energy costs?

Summary of Positions

In the initial proposal BPA determined energy seasons on the basis of withdrawals of hydro energy from storage. BPA, E-BPA-5, F-5. Storage costs are allocated to seasons on the basis of the seasonal production of energy from storage. All other FBS costs are seasonally differentiated on the basis of firm energy produced during each season. BPA, E-BPA-5, F-6. The overall seasonal differentiation of costs is developed from the weighted assignment of total FBS costs to seasons, except that no energy costs are directly allocated to May.

APAC suggests that BPA should apportion the costs of storage based on the seasonal withdrawals from storage. However, thermal costs should be separately apportioned to seasons according to seasonal thermal resource production. Cook, APAC, E-PA-02, Attachment HC-2, 5.

Evaluation of Positions

BPA's method for seasonally differentiating energy costs recognizes that the only costs of energy production that vary by season are the costs of producing energy from storage. All other costs, including costs of thermal generation, are apportioned on the basis of monthly energy production from all FBS resources. BPA, E-BPA-5, F-6.

APAC's method for seasonally differentiating energy costs is illustrated in Cook, APAC, E-PA-01, Attachment HC-2, Schedule 1. This schedule does not account for all thermal costs indicated in the COSA. APAC claims that the cost of thermal generation varies as a result of monthly differences in amounts of power generated and the heat rate at various load levels. Cook, APAC, E-PA-01, 5. However, baseload thermal plants are designed to operate throughout the year, except for planned maintenance, refueling, and forced outages. Outages may occur at any time during the year and are not planned. Thermal resources are added to BPA's system in order to supply needed energy on an annual basis under critical water conditions. Carr & Revitch, BPA, E-BPA-28, 11. As indicated in the TDLRIC Analysis, from a planning perspective increases in demand for energy at any hour of the year, except during May, will require baseload thermal additions. Thus, the costs of providing energy from baseload thermal plants are the same for each hour of the year, except May. BPA, E-BPA-6, 27. Therefore, BPA has selected seasonal periods for generation energy based on the ratios of monthly energy production from storage to the annual total. BPA, E-BPA-5, F-5.

Decision

BPA adds thermal resources to supply needed energy on an annual basis under critical water conditions. With the exception of May, increases in demand for energy at any hour during the year, on a planning basis, are assumed to be met by addition of baseload thermal resources. For this reason, the costs of providing additional baseload thermal resources are identical for each hour of the year, except hours in the month of May. Energy loads in excess of baseload thermal production are served on a seasonal basis by withdrawing stored water from the reservoirs. Because BPA has the ability to shape its resources to meet seasonal energy loads, it is appropriate to differentiate costs seasonally on the basis of withdrawals from storage. On a planning basis, seasonal differences in BPA's thermal costs are nonexistent. BPA, E-BPA-6, 27.

Issue #3

Is BPA's application of the seasonal differentiation of FBS costs to costs of exchange resources appropriate?

Summary of Positions

In the initial proposal BPA seasonally differentiated costs of exchange resources according to percentages developed for FBS costs. BPA, E-BPA-5, F-2. The NWU's argue that costs of exchange resources incurred by BPA do not vary by season. Further, the NWU's suggest that BPA use the seasonal differentiation of costs calculated by exchanging investor-owned utilities to seasonally differentiate the exchange resource. They claim that exchange costs do not vary by season, but assuming there were some reason to seasonally differentiate exchange resource costs, it would be more appropriate to use the seasonal differentiation indicated by the IOU's themselves. Sirvaitis, NWU, E-NW-06, 1-6.

Evaluation of Positions

Usage of electricity varies over the year, resulting in differences in costs which should be reflected in a seasonally differentiated pricing structure. BPA, E-BPA-5, F-1. BPA uses the FBS seasonal differentiation for costs of all resources, including the exchange, because no information is available on the seasonal characteristics of the exchange. BPA, E-BPA-5, F-2. The FBS seasonal differentiation was used as a proxy for the seasonal differentiation of the exchanging utilities themselves. BPA's method provides internal consistency in the seasonal differentiation of costs of all resources. Additionally, it provides revenue and rate stability over time, and is easy to administer and to understand. Soliciting information from exchanging utilities for use in BPA's seasonal differentiation of exchange resources would be an administratively difficult approach.

Decision

It is necessary to seasonsally differentiate exchange resources, because usage of electricity and the resulting costs vary over the year. The use of exchanging utilities' seasonal differentiation of costs by BPA would impose an excessive administrative burden in the verification and application of such data in BPA's rate development process. In the final proposal BPA continues to use the FBS seasonal differentiation for exchange resources. This method for seasonal differentiation of costs of exchange resources conforms with BPA's approach for classification of exchange resources.

D. Allocation of Costs

1. Size of the Federal Base System

Issue #1

Does the COSA reflect the full capability of the Federal hydro system?

Summary of Positions

FBS hydro resources, as shown in Table G-I of the COSA, differ from the FCRPS hydro resources shown in the Loads and Resources Study, BPA, E-BPA-3, Attachment 2, 528, by an amount of hydro resource required to serve loads to which no costs are allocated in the COSA. Revenues are derived from such loads by contractual arrangement; such loads are contractual obligations of the FCRPS hydro resources and are outside the scope of BPA's rate process. Therefore, for ratemaking purposes, these loads, and a corresponding amount of FCRPS hydro resources, are excluded from the load and resource balance developed in the COSA for ratemaking purposes. In rebuttal testimony, BPA reconciled the FBS hydro resource figure in the initial Loads and Resources Study with the FBS hydro resource figure in the initial COSA. Fuqua, BPA, E-BPA-43R, Attachment 1. The FBS hydro resource in the COSA differs from the FCRPS hydro resource in the Loads and Resources Study by 619 average megawatts. Fuqua, BPA, E-BPA-43R, Attachment, 1; Revitch, BPA, TR 5127, 5128. The PGP does not contest the exclusion of this amount of FCRPS hydro resource calculation in the COSA. Garman, et al., PGP, E-PG-01, Table A, 8A. The FBS hydro resources calculated in the COSA are defined by the amount of available hydro resources, as calculated by BPA's resource planning process. BPA, E-BPA-5, G-6. Using the same methodology set forth in E-BPA-43R, Attachment 1, the FBS hydro resource figure in the final Loads and Resources Study reconciles with the FBS hydro resource figure in the final COSA.

The PGP, supported by PPC and APAC, claims that in the COSA the FBS is defined by loads. Garman, et al., PGP, E-PG-01, 6; Opening Brief, APAC, B-PA-01, 67, 68; Opening Brief, PPC, B-PP-01, 1-6. Furthermore, the PGP claims that the amount of Federal hydro resources calculated in the COSA does not represent the full capability of the FBS hydro resources because the COSA does not demonstrate the derivation of the Federal hydro system from BPA's planning process. Garman, et al., PGP, E-PG-06R, 4.

Evaluation of Positions

BPA has reconciled the amount of Federal hydro resources calculated in the COSA with FCRPS hydro resources calculated in a Pacific Northwest Coordination

Agreement (PNCA) type hydro regulation study contained in BPA prefiled testimony. Fuqua, BPA, E-BPA-12, Attachment 4; Fuqua, BPA, E-BPA-43R, Attachment 1. This reconciliation accounted for all but 17 megawatts of difference between 9 months (September 1984 to June 1985, excluding May 1985) averages of COSA hydro resources and BPA resource planning hydro resources in the initial studies.

All loads and resources appearing in the COSA are derived from BPA's Loads and Resources Study. The method used to calculate FBS hydro resources reflects the same assumptions about operation of the hydro system used in BPA's resource planning process. That is, that the Federal hydro resources will be used to serve loads and to balance loads and resources. BPA, E-BPA-5, G-3; BPA, E-BPA-3, Attachment 2, 528. The differences between the FBS hydro resources in the initial COSA and the FCRPS hydro resources in the initial Loads and Resources Study are represented by 619 average megawatts of FCRPS load obligations to which no costs are allocated; 460 average megawatts of interchange energy, advance energy, and FELCC shift; 51 average megawatts of Grand Coulee pumping project load; and 193 average megawatts of unregulated Federal hydro resources. Fuqua, BPA, E-BPA-12, Attachment 4. While the numbers in the final COSA and Loads and Resources Study differ from those in the initial proposal, the methodology is the same. The reconciliation of the hydro resources contained in the COSA with the hydro resources determined by the hydro regulation study used in the Loads and Resources Study demonstrates that the FBS hydro resources calculated in the COSA are entirely derived from and consistent with the Federal hydro resources calculated in BPA's resource planning process.

Decision

BPA has demonstrated through its reconciliation of FBS hydro resources calculated in the COSA with FCRPS hydro resources calculated in a PNCA format hydro regulation study that the FBS hydro calculation in the COSA is entirely consistent with the FCRPS hydro calculation in BPA's Loads and Resources Study. Consequently, the COSA reflects the full capability of the Federal hydro system in the test period.

2. Conservation Costs

BPA has proposed a methodology to allocate conservation costs that reflects the relative benefits of conservation to BPA ratepayers and participants in BPA conservation programs. Issues relating to the theory and implementation of this methodology are described below.

a. Allocation Methodology

Issue #1

Is the marginal minus average methodology an appropriate cost allocation methodology, and what benefits should be reflected in the methodology?

Summary of Positions

In the initial proposal BPA presented a methodology that divides costs according to two types of benefits: rate benefits and participant benefits. The methodology proposed by BPA allocates costs to BPA rates in proportion to the benefit received by BPA ratepayers. The remaining costs in proportion to benefits received by conservation participants are allocated to a regional load charge. Metcalf, BPA, E-BPA-30, 3-4; Metcalf, BPA, TR 5271, 5289; Metcalf, BPA, E-BPA-05, 26-27, G-18, G-20.

The formula that BPA used in the initial proposal to determine the portion of costs assigned to BPA rates is ((M-L)/M)xT. M is the avoided marginal cost of new resources (from BPA's TDLRIC Analysis), L is lost sales revenue at BPA's rate (PF for public agencies, NR for IOU's), and T is the total cost of conservation determined in BPA's COSA. The amount of costs allocated to participants' benefit is L/M. Metcalf, BPA, E-BPA-05, G-18; Metcalf, BPA, E-BPA-30, 3-4. The formulas are adjusted for exchanging IOU's to recognize the BPA rate benefit of reduced exchange loads. In the initial proposal, BPA cost allocation formulas reflected the assumption that all BPA-funded conservation for exchanging utilities would be for residential programs only. BPA, E-BPA-05. In rebuttal testimony, BPA adjusted the formula for exchanging utilities to reflect that BPA funds conservation in more than the residential customer class of utilities participating in conservation programs, but that the conservation rate benefit is received only on exchangeable loads. Metcalf, BPA, TR 5233, 5255.

SCL argues that BPA should follow a rigorous cost-follows-benefits methodology or, as an interim solution, use the 1982 method for allocating costs to all firm BPA loads. Fiddler, SCL, DP 35; Fiddler, SCL, E-SL-01, 3. SCL identifies conservation benefits as lower rates and program funding. Fiddler, SCL, E-SL-01, 3, 8.

The ICP and PGE agree that BPA should divide conservation costs between rates and regional loads. However, they offer a different definition of benefits and, therefore, a different formula to split the costs between rates and regional loads. White, ICP, E-IC-3, 7-8; White, PGE, E-GE-01R, 2. The first formula the ICP offers to calculate rate benefits is ((M-L)/C) x T where: M = BPA's long run cost of resources determined by BPA's near-term cost effectiveness policy, L is BPA's average firm rate, C is the long-term conservation cost, and T is total conservation cost in the test year. White, ICP, E-IC-03, 8-9. OPUC supports the ICP allocation formula. OPUC, B-OP-01, 16. The ICP later offered another allocation method that would separate costs into two components: savings acquisition expenditures and program development costs. Program development costs would be allocated to rates and the acquisition expenditures were split between rate benefits and participant benefits using the ICP [(M-L)/C)] formula. The costs allocated to participant benefits would be recovered through a charge based on reimbursement levels. Opening Brief, ICP, B-UP-01, 11-13.

PNGC supports the concept of the BPA marginal minus average methodology to allocate conservation costs. Johnson, PNGC, E-PN-04, 1. PNGC notes that conservation costs must be spread over regional loads to be equitably allocated. Reply Brief, PNGC, R-PN-01, 4-6. However, PNGC argues that the allocation of conservation costs should reflect the benefits to each customer group based on the stacking of resource pools developed in the Regional Act. Johnson, PNGC, E-PN-04, 1-3; Johnson, PNGC, E-PN-07R, 1-2; Opening Brief, PNGC, B-PN-02, 2-3; Reply Brief, PNGC, R-PN-01, 9-11.

Central Lincoln PUD argues that the proposed BPA methodology is unworkable, because benefits are uncertain and difficult to define. Moxness, Cen. Lin., E-CL-01, 5, 6.

WWPUD's support the marginal minus average cost allocation methodology proposed by BPA. Opening Brief, WWPUD, B-WW-01, 42-43, 45. They noted that BPA did not include the percent of residential loads for exchange customers in BPA's initial formula for allocating costs to the rate benefit. BPA adopted their suggested formula to properly reflect the rate benefit for exchange loads. Hutchison, et al., WWPUD, E-WW-01, 32; Hutchison et al., WWPUD, TR 5255, 5233.

Evaluation of Positions

SCL, the ICP, and PGE argue that the benefits of BPA conservation programs accrue to BPA ratepayers and to individual utility consumers participating in BPA funded programs. Fiddler, SCL E-SL-01, 3, 8; White, PGE, E-GE-01R, 2; White, ICP, E-IC-03, 7-8; Reply Brief, ICP, R-UP-01, 2-3; Opening Brief, B-UP-01, 7. They agree with BPA's analysis that benefits to BPA ratepayers occur because conservation allows BPA to avoid the purchase of costly new generating resources. They disagree with BPA's definition of participant benefits as the cost savings from the power purchases a utility avoids because the utility or other entity participates in a BPA-funded conservation program. They deny that benefits are received by utilities participating in BPA-funded programs unless the reduced power purchases are greater than the loss of sales revenue caused by conservation. White, ICP, E-IC-03, 8; Fiddler, SCL, E-SL-02SR, 6; White, PGE, E-GE-02R, 6; Reply Brief, ICP, R-UP-01, 3; Opening Brief, B-UP-01, 7. The distinction between a utility and the utility's consumer is unclear. If conservation reduces the total cost of electricity needed to serve a utility's consumers' needs, then that utility and its consumers benefit. Metcalf, BPA, E-BPA-05, 26. It is not necessary for a utility's unit rates to be lower for the utility to benefit. SCL, the ICP, and PGE have merely identified a conserver, nonconserver equity problem on their own systems. It would be inequitable to distort the allocation of costs at the wholesale level to attempt to solve cost allocation problems at the retail level. The marginal minus average cost allocation methodology deals with the issue of equity between conservers and nonconservers at the wholesale level. It is up to each utility to deal with the conserver, nonconserver equity issue at the retail level. Therefore, participant benefits are relevant to the division of costs between BPA rates and regional loads.

BPA disagrees with SCL's analysis and proposed resolution of the issue. First, SCL has advocated following a rigorous cost-follows-benefits analysis. They argue that BPA has not considered all of the benefits of conservation. Fiddler, SCL, E-SL-01, 8, 10. It is true that BPA has not identified an exhaustive list of benefits resulting from BPA funded conservation efforts. However, it is not necessary to identify all possible conservation benefits to develop a reasonable cost-allocation methodology. BPA has recognized the regional nature of the BPA funded programs and has identified the major benefits of the programs. Metcalf, BPA, BPA-30, 3-4. BPA has not recognized benefits arising from conservation programs funded by entities other than BPA because BPA is not responsible for the costs of those programs. To the extent that those programs benefit BPA ratepayers and meet other appropriate criteria, they may qualify for billing credits.

SCL has noted that there is a sharing of the costs of the installed conservation measure between utilities and end-use consumers receiving program measures. They maintain that BPA's cost allocation methodology is inconsistent with the delivery of conservation measures to end-use consumers because: (1) BPA only allocates BPA's share of the installed measure's cost; and (2) BPA's method of allocating costs over regional loads may not allocate costs in proportion to each utility's reimbursement for program measures installed in their service area. Fiddler, SCL, E-SL-01, 10; Fiddler, E-SL-02R, 11-12; Reply Brief, SCL, R-SL-01, 11-12. The sharing of costs between utilities and end-use consumers is not related to the COSA conservation cost allocation methodology, however, BPA is only responsible for the allocation of BPA's conservation costs. Additional costs of program measures are appropriately paid for by the end-use consumer who experiences a direct benefit. Hickey, BPA, TR 4319. The conservation charge, based on regional loads and also program reimbursements is designed to allocate costs according to benefits received by utilities participating in BPA funded conservation programs.

SCL also maintains that BPA's cost allocation methodology does not treat the acquisition of conservation and generation resources equitably. They argue that utilities offering generating resources to BPA do not experience a loss in revenues from reduced loads and do not pay a contract charge. Fiddler, SCL, E-SL-02R, 8-9, 13-14; Fiddler, SCL, E-SL-01, 3, 5; Opening Brief, SCL, B-SL-01, 19-20; Reply Brief, SCL, R-SL-01, 21. Criteria for acquisition of resources are established in the Regional Act and considerations reflected in BPA's Draft Near-Term Resource Policy. BPA studies placed generating resources and conservation resources on a comparable basis for the test year. Hickey, BPA, TR 4251-4253. BPA acquires generating resources and conservation resources according to the criteria for acquisition of these resources independently of any cost allocation procedures. After BPA decides to acquire resources, each utility can assess their operating characteristics and determine if it is reasonable to offer BPA a generating resource or to pursue conservation programs.

Another problem with SCL's analysis is their proposed alternative methodology for allocating costs according to BPA loads. One of BPA's concerns in designing a method to allocate conservation costs is that the costs need to be equitably allocated between generating and nongenerating utilities. Metcalf, BPA, E-BPA-05, 6-16; Metcalf, BPA, TR 5331-5332. A cost-follows-BPA-loads method does not solve the problem of allocating conservation costs equitably between generating and non-generating utilities. As noted by WWPUD's and PNGC, if BPA adopted SCL's proposal, a utility that served part or all of its own load would be eligible across its entire load for BPA programs without paying a proportionate share of the program costs. Opening Brief, WWPUD, B-WW-01, 42-43, 45; Reply Brief, PNGC, R-PN-01, 4-5. SCL argues that the equity criterion is vague and places generation and conservation resources on unequal footing. Reply Brief, SCL, R-SL-01, 13-14. As discussed earlier, BPA maintains that acquisitions of generation and conservation resources are equitably treated in the studies that BPA performs to determine conservation and resource acquisitions.

The ICP proposals allocate far more costs to BPA rates than BPA's methodology. Rather than reflect a proportional allocation to rates and regional load based on rate and participant benefits, the ICP proposal allocates costs to rates by comparing long-term rate benefits to long-term conservation costs. White, ICP, E-IC-03, 8-9; Opening Brief, B-UP-01, 12. This methodology ignores participant benefits, and in a situation where the long-term rate benefit exceeds the conservation costs, could cause all costs to be recovered from rates. The ICP agrees that this could occur and maintains that it would be a proper allocation of costs if rate benefits are sufficiently large. Reply Brief, R-UP-01, 4. This does not answer BPA's argument that two groups receive conservation benefits, ratepayers and participants, and costs should be allocated proportionally according to benefits received. Like SCL's proposed solution, the ICP methodology could inequitably allocate costs between generating and nongenerating utilities.

The PNGC proposed modifications to the marginal minus average formula to reflect different conservation benefits for each rate pool. They maintain that rate benefits for 7(b) customers should be valued at the cost of the exchange rather than at BPA's LRIC. Johnson, PNGC, E-PN-04, 2; Johnson, PNGC, E-PN-07R, 1-2; Opening Brief, PNGC, B-PN-02, 2-3; Reply Brief, PNGC, B-PN-01, 10. It is true that there may be different benefits for each rate pool, but the total rate benefit for BPA is determined by the resource cost BPA is able to avoid when utilities conserve. Therefore, the formula BPA uses to split costs between rates and regional load must use the LRIC as the avoided purchase cost. If the cost of the exchange is used for 7(b) and 7(c) loads, and LRIC is used for 7(f) loads, then not enough costs are allocated to BPA rates.

Decision

The marginal minus average cost method as modified by BPA's rebuttal testimony is used to allocate conservation costs. This method recognizes the regional nature of BPA programs. It reflects the short and long-term benefits of conservation to both BPA and non-BPA loads. It equitably allocates costs between generating and nongenerating utilities.

Issue #2

Should conservation costs assigned to rates be directly allocated to loads served by exchange resources, and/or should the regional load charge be allocated to the DSI's?

Summary of Positions

In the initial proposal BPA did not allocate conservation costs directly to loads served by exchange resources. These loads bear conservation costs because the conservation charge and power purchased from BPA to serve net requirements are included in exchanging utilities' average system costs. Metcalf, BPA, E-BPA, 30, 8; Metcalf, BPA, TR 5256, 5257. BPA demonstrated in rebuttal testimony that loads served by exchange resources pay the same unit regional load charge as program participants. Metcalf, BPA, E-BPA-46R, Attachment 2. To allocate costs directly to loads served by exchange resources would be a double allocation of similar costs to the loads served by exchange resources. Metcalf, BPA, BPA-30, 8; Metcalf, BPA, E-BPA, TR 5299.

The WWPUD's, ICP, APAC, OPUC, and PNGC all argue that conservation costs should be directly allocated to the DSI's . Carter, OPUC, E-OP-01, D6; Johnson, PNGC, E-PN-07R, 1-2; Johnson, PNGC, DP 81; Opening Brief, WWPUD, E-WW-01, 47-48; Hutchison, et al., WWPUD, E-WW-01. 31; McCullough, NWU, E-NW-05, 10; White, ICP, E-IC-03, 9-10; Cook, APAC, E-PA-02, 19; Springer, PNGC, TR 9015; Opening Brief, PNGC, B-PN-02, 5-6; Opening Brief, ICP, B-UP-01, 5-6; Opening Brief, OPUC, B-OP-01, 17; Opening Brief, APAC, B-PA-01, 89; Reply Brief, APAC, B-PA-01, 26-27. The WWPUD's argue that the DSI's should be allocated conservation costs in proportion to their load. Hutchison, et al., WWPUD, E-WW-01, 30-31; Opening Brief, WWPUD, E-WW-01, 47-48. They also recommend that the average system cost contract be amended so that the conservation charge cannot be exchanged. Hutchison, et al., WWPUD, E-WW-01, 31. NWU's recommend that BPA allocate the costs associated with rate benefits in accordance with the allocation of all other BPA costs. McCullough, NWU, E-NW-05, 10. APAC and ICP recommend allocating the rate costs associated with benefits uniformly over all firm loads. White, ICP, E-IC-03-9; Cook, APAC, E-PA-02, 19. Additionally, the ICP recommends allocating a portion of the regional load charge to the DSI's. The ICP views the regional load charge as a tax to be applied to all regional loads. White, ICP, E-IC-03, 10; Opening Brief, ICP, B-UP-01, 8. OPUC and PNGC recommend that BPA allocate conservation costs to the DSI's in proportion to their load. Carver, OPUC, E-OP-01, D4-6; Johnson, PNGC, DP 84; Johnson, PNGC, E-PN-07R, 1-2; Springer, PNGC, TR 9015; Opening Brief, PNGC, B-PN-02, 5-6; Reply Brief, PNGC, R-PN, 01, 11-13.

The DSI's support BPA's analysis that double counting of conservation costs can be avoided if costs are not directly allocated to loads served by exchange resources. Peseau, DSI, E-DS-10, 38. Reply Brief, DSI, R-DS-01, 46-47.

Evaluation of Positions

Parties to the rate case have argued that the DSI's receive benefits from conservation, but are not directly allocated conservation costs. Carter, OPUC, E-OP-1, D4; McCullough, NWU, E-NW-05, 8-9; White, ICP, E-IC-03, 6; Cook, APAC, E-PA-02, 21; Opening Brief, WWPUD, E-WW-01, 47-48; Opening Brief, ICP, B-UP-01, 6; Opening Brief, OPUC, B-OP-01, 17; Reply Brief, R-UP-01, 5-6. OPUC argues that the DSI's will receive rate benefits and they could receive load reduction benefits. Carver, OPUC, E-OP-1, D4. NWU's and ICP argue that the DSI's benefit from reduced average system costs. McCullough, NWU, E-NW-05, 8-9; White, ICP, E-IC-03, 6; Opening Brief, ICP, B-UP-01, 6. The ICP also argues that the indirect costs the DSI's pay are not in proportion to their load. Opening Brief, ICP, B-UP-01, 5. APAC argues that the DSI's benefit because BPA serves top quartile loads with Federal energy, and that the DSI's will benefit from post-1985 rates when there are only two rate pools. Cook, APAC, E-PA-02, 21.

NWU's and WWPUD's argue that allocating conservation costs directly to the DSI's will not be double counting of conservation costs because the costs of conservation included in ASC are offset by benefits. McCullough, NWU, E-NW-05, 8-9; Opening Brief, WWPUD, E-WW-01, 47-48. The ICP argues that double-counting only occurs in the exchange of the conservation charge. Therefore, BPA should assign costs to the DSI's through rates. Reply Brief, ICP, R-UP-01, 6-7.

It is instructive to list all the ways in which conservation costs or the costs of alternatives affect the IP-83 rate. The cost of exchange resources include: (1) exchanging public agency PF purchases; (2) IOU PF (WNP-1), CF and NR purchases; (3) ASC's deemed equal to the PF rate; (4) BPA conservation contract charges; (5) the cost of utility-financed conservation programs; and (6) the cost of alternate resources for utilities that neither participate in BPA's conservation programs nor implement their own programs. Metcalf, BPA, E-BPA-30, 8; Metcalf, BPA, TR 5256-5259, 5285-5286. The pricing of the top quartile is influenced heavily by the level of the Nonfirm Standard rate which includes conservation costs. Metcalf, BPA, E-BPA-32, 7, 51; Metcalf, BPA, E-BPA-7, 57. BPA's conservation program (and indirectly, other regional conservation programs) contributes to the short term surplus BPA projects will exist during the test year, and the underrecovery of surplus costs is allocated principally to the DSI's. Metcalf, BPA, E-BPA-32, 12; Metcalf, BPA, E-BPA-7, 64; Metcalf, BPA, E-BPA-32S, Attachment 1. DSI's indirectly pay for conservation costs associated with rate benefits, so therefore they should not have additional costs allocated directly through the rates.

The DSI's are not eligible for conservation acquisition funding during the rate period, Metcalf, BPA, TR 5268, and no party has quantified any rate benefits that they might receive.

Decision

Conservation costs assigned to rates have not been allocated directly to loads served by exchange resources. Loads allocated exchange resource costs are indirectly paying for conservation costs through payment of exchange costs. Under the current average system cost methodology, utilities can include in their average system cost the conservation charge net of conservation program reimbursements. Conservation costs need not be allocated to the top quartile, because top quartile pricing already includes the conservation costs included in the nonfirm standard rate. The DSI's are also allocated most of the costs resulting from unsold surplus. These costs are in part attributable to conservation programs in the test year. In addition, since BPA does not have any conservation acquisition programs that are planned to be available for the DSI's in the rate period, it is appropriate that they are not directly allocated a share of the regional load charge.

Issue #3

What method should be used to allocate the costs assigned to rates among customer classes?

Summary of Positions

BPA allocates the costs assigned to rates among customer classes using allocation factors that divide costs proportionally among loads not served by exchange resources. Metcalf, BPA, E-BPA-30, 5; Metcalf, E-BPA-05 G-36. PNGC maintains that the allocation of rate costs among customer classes should reflect the stacking of resource pools identified in the Regional Act. PNGC proposed formulas that base the rate allocation on long-term rate benefits accruing to each rate pool. Johnson, PNGC, E-PN-04, 3; Springer, PNGC, TR 9014-9015; Opening Brief, PNGC, B-PN-02, 3-5; Reply Brief, PNGC, B-PN-01, 10-11. The ICP recommends allocating the cost of rate benefits to customer classes on an equal millage basis to all BPA load. White, ICP, E-IC-03, 9.

Evaluation of Positions

The ICP points out the difficulties inherent in adopting the PNGC proposal. They argue that long-term rate pool benefits cannot be quantified because of uncertainty about post 1985 rate design. They note that short-term benefits may be quantified, but may not be representative of the distribution of long-term benefits. White, ICP, E-IC-03, 9. PNGC argues that certainty is provided by their proposal because it is based on the stacking directives of the Regional Act. Reply Brief, PNGC, R, PN-01, 11.

The PNGC proposal would increase the costs allocated to the 7(f) rate pool. Such an allocation could lead to a reduction in sales under this rate. PNGC agrees that this could occur, and argues that it is appropriate. Reply Brief, PNGC, R-PN-01, 11. However, if costs are allocated to the 7(f) pool but IOU's make no purchase under the NR-83 rate schedule, BPA would fail to recover those conservation costs. Any significant additional allocation of conservation costs to that pool will render the power unmarketable, because of the small amount of load and the alternative rates available to the IOU's for purchases. Metcalf, BPA, E-BPA-45R, 4. Additionally, the accepted allocation method to divide costs among customer classes is through allocation factors based on loads. BPA has applied allocation factors for conservation costs in a manner consistent with the allocation of the rest of BPA's costs. Metcalf, BPA, E-BPA-5, Table 12, 7.

Decision

Conservation costs assigned to rates have been allocated to loads not served by exchange resources. A cost-follows-benefits method is not a practical allocation tool except for the step that splits costs between rates and regional loads. PNGC's allocation method is not practical for this rate period because few purchases of power at the NR-83 rate are projected and the IOU's have several alternatives to the NR-83 schedule that could results in fewer than projected NR-83 purchases and an underrecovery of allocated costs.

Issue #4

Does the Regional Act prohibit BPA from recovering its costs through means other than its rates?

Summary of Positions

SCL claims that BPA is prohibited from recovering its conservation costs through any means other than its rates. Opening Brief, SCL, B-SL-01, 10-17; Reply Brief, SCL, R-SL-01, 3.

Evaluation of Positions

SCL alleges that the Regional Act prohibits BPA from recovering its conservation costs through any mechanism other than its rates. They point to the use of the word "shall" in sections 7(a) and 7(g) of the Act as a clear indication of this intent. However, sections 7(a) and 7(g) are not intended to restrict BPA to recovering all costs through one form of charges, but rather obligates BPA to ensure that rates are sufficient to recover total system costs and repay the Treasury.

Whether BPA could assess charges in addition to its rates was not an issue in the developmentof the Regional Act. SCL cites no legislative history indicating the existence of such an issue. Indeed, BPA has been assessing charges outside its rates for years. Examples include charges for work done by BPA on customers' transmission facilities through various Trust Agreements.

One of the purposes of the Regional Act is:

> "(4) to provide that the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources to meet the region's electric power requirements. . ." 16 U.S.C. §839(4)
> (Supp. V 1981).

This section clarifies that the law that BPA's customers pay the system's costs, not the nation's taxpayers.

Section 7(a) was described in the House Interior Committee Report as continuing "the requirement of existing law that BPA set its rates to recover, in total, the full cost (but not more than the full cost) of its financial obligations." House Report 96-976, Part II, 52 (hereafter "Interior Report"). Clearly, the focus of the sentence is the recovery of costs, not the sanctity of rates as the sole vehicle for cost recovery. The Senate Report on S. 885 states that "these rates shall continue to be established at levels to recover revenues sufficient to pay all of the Administrator's costs." (emphasis added). The only mandate found in "existing law" which is continued by section 7(a) is that found in section 7 of the Bonneville Project Act, 16 U.S.C. § 832f and in section 9 of the Federal Columbia River Transmission System Act, 16 U.S.C. § 838g to recover "the cost of producing and transmitting such electric energy." Nothing in "existing law" even suggests that Congress ever intended to bar BPA from introducing cost recovery mechanisms other than rates.

Section 7(g) provides the Administrator the flexibility and explicit authority to allocate the listed costs to power sales customers within the listed guidelines and in a manner he finds equitable. It is a precautionary provision, added to avoid arguments that the Administrator had the authority to allocate and assess only those costs specifically mentioned elsewhere in section 7. The legislative history of section 7(g) of the Regional Act states the continuing obligation very clearly: "BPA's obligation and that of its customers is to ensure that all costs are recovered." House Commerce Committee Report, House Report No. 96-976, Part I, 69. The Interior Report states that "section 7(g) provides for the allocation of costs and benefits that are not otherwise allocated by other provisions of this bill or other applicable laws currently in effect." Id. at 53. If the intent of Congress in section 7(g) had been to limit cost recovery to the rates vehicle, one would expect that all of the legislative history would be clear and consistent on that point. The Interior Report provides the one clear and consistent interpretation of section 7(g), i.e., it is a general grant of authority to the Administrator to allocate costs and benefits other than those specifically mentioned elsewhere in BPA's controlling statutes.

SCL also claims that section 6(j)(1) of the Regional Act restricts recovery of conservation costs to the rate vehicle. Section 6j(1) states:

> "All contractual and other obligations required to be carried out by the Administrator pursuant to this Act shall be secured solely by the Administrator's revenues received from the sale of electric power and other services..."

Again, the focus of the section is misperceived by SCL. Clearly the section says nothing about any requirement to raise revenues in a particular way. Its reference to "revenues received from . . . other services" says exactly the opposite. SCL cites no legislative history in support of their view of section 6(j)(1) because there is none. The legislative history clearly states the intent: as a self-financing agency, BPA's revenues (and not the revenue-raising power of the Federal Treasury) are the sole security for BPA's obligations. Interior Report at 51.

Decision

It is appropriate to recover a portion of test year conservation costs through a conservation charge. BPA has the legal authority to recover conservation costs through collection mechanisms other than rates.

The BPA method and the ICP proposal are essentially the same except for the loads over which the costs are spread.

b. A Cap On the Contract Charge

Issue #1

Should a cap be placed on the conservation charge?

Summary of Positions

In the initial proposal, to encourage participation in BPA programs, BPA did not tie the conservation charge to the level of reimbursement. Additionally, BPA argued that the level of the conservation charge is a relatively small amount when compared to utilities' retail rates and BPA's wholesale power rates. Therefore, the conservation charge should not be a major disincentive to signing the conservation contract. Metcalf, BPA, E-BPA-30, 71; Metcalf, BPA, TR 5235, 5243. If the conservation charge were tied to the reimbursement payments, some utilities might cut back on BPA programs in order to decrease their conservation charge. Metcalf, BPA, E-BPA-30, 11; Metcalf, BPA, TR 5334.

The ICP agrees that a conservation charge is appropriate for recovering some conservation costs because of the regional nature of BPA's programs. White, ICP, E-IC-03, 2. However, the ICP and OPUC maintain that an uncertain and unconstrained conservation charge would be a disincentive to signing the conservation contract. White, ICP, E-IC-03, 2-3; Carver, OPUC, E-OP-01, D5; Opening Brief, OPUC, B-OP-01, 18. To deal with this disincentive they have proposed that a lid be placed on the conservation charge at the point where the present value of the conservation charge is equal to the present value of program reimbursements. Carver, OPUC, E-OP-01, 5; White, ICP, E-IC-03, 3-4; Opening Brief, ICP, B-UP-01, 9-11. The ICP argues that if a lid is not imposed, that BPA should adopt the alternate allocation methodology presented in their opening brief. This methodology ties the conservation charge to program reimbursements. Opening Brief, ICP, B-UP-01, 11.

SCL argues that the conservation charge is a disincentive to sign the conservation contract. Fiddler, SCL, E-SL-01, 6-7. SCL supports the 1982 cost-follows-BPA-loads method as a solution to this disincentive to sign the contract. Fiddler, SCL, E-SL-01, 11. However, in cross-examination, SCL also agreed that a lid on the conservation charge may remove some of the disincentive to sign the contract. Fiddler, SCL, DP 44. WWPUD's oppose the lid to the conservation charge. Hutchison, et al., WWPUD, E-WW-02R, 24-26.

Evaluation of Positions

The issue of the disincentives surrounding the conservation charge can be divided into two parts. First, the level of the conservation charge in relation to program benefits can be a disincentive to sign the contract. SCL, ICP and OPUC all emphasize this disincentive. Fiddler, SCL, E-SL-01, 6-7; White, ICP, E-IC-03, 2-3; Carver OPUC, E-OP-01, 05. The other disincentive identified is the disincentive to participate fully in BPA programs if the contract charge is tied to funding levels. BPA and WWPUD's emphasize this disincentive. Metcalf, BPA, E-BPA-30, 1; Metcalf, BPA, TR 5235, 5243; Hutchison, et al., WWPUD, E-WW-02R, 24-26.

ICP, OPUC, and SCL argue that a lid on the conservation charge would lessen or eliminate the disincentive to sign the conservation contract. Carver, OPUC, E-OP-01, 5; White, ICP, E-IP-03, 3-4; Fiddler, SCL, DP 44. WWPUD's in rebuttal argued that this proposal is inequitable because the proposal does not include a lid on regional load charges recovered through rates. Hutchison, et al., WWPUD, E-WW-02R, 26. WWPUD's also pointed out that the perceived problem of uncertain and unconstrained charges in the conservation charge is no different from other BPA rates. Hutchison, et al., WWPUD, E-WW-02R, 25. It is important to note that the disbursements, on which the proposed lid is based, represent only a portion of BPA's costs. Metcalf, BPA, TR 5334. BPA argues that the charge should not be a disincentive because the conservation charge is small in comparison to BPA rates and utility retail rates. Metcalf, BPA, E-BPA-30, 11. SCL maintains that over time the conservation charge will be significant. Reply Brief, R-SL-01, 15.

The ICP offered another allocation methodology as an option to address the alleged disincentives to sign the conservation contracts caused by BPA's conservation charge. This methodology would first split conservation costs between costs associated with program development and costs associated with conservation program acquisition expenditures. In the test year, conservation acquisition programs consist of the Street and Area Lighting Program and the

Residential Weatherization Conservation Program. Program development costs would be allocated to rates and acquisition expenditures would be split between rate benefits and participant benefits using the [(M-L)/C] formula. Costs allocated to participant benefits would be recovered proportionally from utilities according to the level of their program reimbursements. Opening Brief, ICP, B-UP-01, 11-13.

The concept of linking at least part of the conservation charge to program reimbursements has merit. BPA disagrees with basing all of the conservation charge on reimbursements because it could serve as a disincentive to participate fully in conservation programs. Metcalf, BPA, TR 5334. Additionally, program development costs should be shared by all program participants because all participants benefit from these expenditures. Metcalf, BPA, TR 5334.

BPA agrees with the analysis of the WWPUD's and opposes a lid to the conservation charge.

Decision

In the Evaluation of the Record, BPA proposed that it would not impose a cap on the conservation charge. In reviewing the parties' replies to the Evaluation of the Record, BPA recognized that the conservation charge needed to be modified to address the alleged disincentive to sign the conservation contracts caused by the proposed conservation charge. However, BPA does not agree that a cap to the conservation charge is an equitable solution.

BPA has decided to apply the reasoning behind the ICP cost allocation methodology to the design of the conservation charge. BPA has split the conservation charge into two parts: (1) a load charge recovered over non-BPA loads that is associated with program development costs and conservation acquisitions under the current conservation contracts and (2) a reimbursement charge associated with conservation acquisitions starting November 1, 1983, under BPA's new conservation contracts.

By splitting the conservation charge between the load charge and reimbursement charge, BPA insures recovery of program development costs and prior expenditures and also allows utilities control over part of their charge by tying the reimbursement charge to current program acquisition expenditures. In developing the charge, BPA assumed that utilities paying the two part charge would be allocated program acquisition expenditures in proportion to their regional load. If the utility spends less than its regional load share, their contract charge will be proportionately reduced.

In developing the new conservation charge, it is appropriate to distinguish between the two types of requirements customers, metered requirements and computed requirements. Reply Brief, PPC, R-PP-02, 3. Most metered requirements customers purchase all their power requirements from BPA; the rest are required to operate their resources in a contractually specified manner. BPA, E-BPA-7, 30. Computed requirements customers have flexibility in the use of their resources and purchase power from BPA as a supplement to their own firm resources. BPA, E-BPA-7, 29-30.

Some metered requirements customers have small amounts of non-BPA load because they own or have contracts for generation such as Columbia Storage Power Exchange (CSPE), shares of the Boardman coal plant, small hydro, and shares of the mid-Columbia hydro projects. BPA, E-BPA-3, Attachment 2, 559-567. Metered requirements customers with contractually specified generating resources lack the flexibility in making power purchases from BPA that computed requirements customers have. BPA, E-BPA-7, 30; BPA, E-BPA-4, 20. Therefore, metered requirements customers with non-BPA generation are more similar in their operating characteristics to other metered requirements customers than they are to computed requirements customers. Thus, it is appropriate to assess a conservation charge on non-BPA loads of metered requirements customers that is the same as the per unit regional load charge paid through the priority firm rate. Computed requirements customers will be assessed the two-part conservation charge in the manner described above.

This modification to the conservation charge methodology to reflect concerns raised by the ICP and SCL insures that all metered requirements customers are treated the same, and allows computed requirements customers to have control over their conservation charge by tying the reimbursement charge to the level of their participation in BPA conservation acquisition programs.

c. Implementation of Regional Load Charge

Issue #1

How should the non-BPA load of an exchanging utility be calculated?.

Summary of Positions

In the initial proposal, the non-BPA load of public utilities was calculated as retail sales less requirements on BPA. BPA, E-BPA-05. For IOU's, non-BPA load was calculated as retail sales less BPA requirements purchases less exchange purchases. Therefore, total load for public utilities equaled retail sales plus exchange load and for IOU's total load equaled retail sales. Metcalf, BPA, E-BPA-45R, 3. Responding to comments made by PNGC, in rebuttal testimony BPA stated that non-BPA load was defined for all customers as retail sales less requirements. Metcalf, BPA, E-BPA-45R, 3-4, Attachment 2, 1.

PNGC recommended that BPA add total system loads to exchange loads for determining the total regional load. Johnson, PNGC, E-PN-04, 3-5. PGE and OPUC recommend that BPA follow the method established in the initial proposal. White, PGE, E-GE-02SR, 1-2; White, PGE, E-GE-01R, 6; Opening Brief, OPUC, B-OP-01, 18.

Evaluation of Positions

BPA demonstrated that if non-BPA loads are defined as retail sales the regional load charge is the same for all customer classes net of the exchange. Metcalf, BPA, E-BPA-45R, 3-4, Attachment 2, 1. PGE argues that this is the incorrect way to view the exchange transaction. Instead, they look at what happens to the average system cost of utilities when they exchange the conservation charge. White, PGE, E-PG-02SR, 3-5; White, PGE, E-PG-01R, 5-6. PGE's demonstration that the average system costs of exchanging utilities include the benefits of conservation as well as the contract charges, White, PGE, E-PG-02SR, 3-5, is beside the point and contradicts the assertion that conservation will not lower retail rates (and thus ASC) because the lost revenue exceeds the cost of additional purchases. White, ICP, E-IC-03, 8. The ICP argues that conservation can cause a utility's ASC to decrease while the retail rate increases because the retail rate is larger and includes non-power costs. Reply Brief, R-UP-01, 9. OPUC supports the ICP and argues that utilities should be able to exchange their conservation charge. Opening Brief, OPUC, B-OP-01, 17-18. PNGC demonstrated that non-exchange loads of exchanging utilities pay the full conservation charge only if non-BPA loads are defined as retail sales less BPA requirements purchases. Johnson, PNGC, E-PN-04 51; Opening Brief, PNGC, B-PN-02, 7; Reply Brief, PNGC, R-PN-01, 14.

Decision

Non-BPA loads are determined by subtracting BPA requirements purchases from retail sales. BPA loads equal exchange loads plus BPA requirements purchases. Therefore, total loads equal retail sales plus exchange load. This results in an equal unit charge for all loads after tracing the effects of the exchange. BPA believes that an equitable allocation of the regional load charge occurs when all loads pay the same unit charge, net of the exchange .

Issue #2

Should the conservation charge be determined by using actual loads or forecast loads?

Summary of Positions

BPA used forecast loads in the initial proposal to determine the level of the regional load charge and for the collection of the conservation charge. The part of the regional load charge rolled back into the rates is collected from actual loads. Metcalf, BPA, E-BPA-45R, Attachment 1. The ICP in surrebuttal testimony advocated using forecast loads to determine the mills/kWh level of the charge, and actual loads to calculate the total conservation charge for each utility. White, PGE, E-GE-02SR,8. The PNGC and the PPC advocated in reply briefs that BPA should use actual loads to calculate the conservation charge. Reply Brief, PNGC, R-PN-01, 24-25; Reply Brief, PPC, R-PP-02, 1-3.

Evaluation of Positions

The ICP noted that the regional load charge paid by BPA customers is based on actual loads, while the conservation charge is based on forecast loads. They maintain that this causes a utility with a non-BPA load that is less than the forecast to overpay the conservation charge. White, ICP, EGE-02SR, 9.

Forecast loads were originally chosen for the conservation charge because they yield a certain charge for which utilities can plan, and to ease administration of the conservation charge. Forecast non-BPA loads are determined as part of the rate case and are subject to review by parties to the case. Actual loads represent a reasonable way of calculating the conservation charge. However, at present, BPA has not established a procedure to determine actual non-BPA loads. The billing provision of the conservation contract which requires bills to be rendered forty days prior to the end of the billing period, appears to be designed for forecast loads but could be used with actual loads only through the use of estimated bills. Some mechanism for reporting and verifying actual loads also would be required. In its reply brief, PNGC argues that basing the charge on actual loads would be more equitable because if PNGC sells the utility shares of the Boardman coal plant during the rate period, PNGC members would still be required to pay a conservation charge even though their non-BPA load would be zero. They additionally argued that BPA has enough time before the bills are prepared to determine a mechanism for collecting non-BPA loads. Reply Brief, PNGC, R-PN-01, 24-25.

Decision

BPA's initial decision was to use forecast loads for calculation of the conservation charge. After reviewing the arguments made in reply briefs, BPA has decided to prepare an estimated bill for the conservation charge using forecast loads and reimbursements and then prepare a final bill based on actual loads and actual reimbursements. The determination of and mechanism for submitting actual loads will be established by BPA prior to June 30, 1984.

Issue #3

Should BPA consider purchases made at the NR rate as a BPA load?

Summary of Positions

In the initial proposal BPA set the NR-83 energy charge slightly higher than the SP-83 energy charge. The differential is primarily due to allocation of the conservation regional load costs to the new resource load. No conservation regional load costs have been allocated to surplus firm power. Metcalf, BPA, E-BPA-32, 44. In rebuttal testimony, BPA counted purchases made at the NR rate as a non-BPA load and recovered conservation costs allocated to this load through the conservation charge. This change was made to enhance the marketability of power at the NR rate. Metcalf, BPA, E-BPA-45R, 4.

The ICP states that an NR rate set higher than the surplus firm power rate "has the unfortunate consequence of limiting or eliminating new resource loads, thus thwarting a key purpose of the Regional Act and the power sales contracts, namely the provision of power and energy for investor-owned utility firm load requirements." Lauckhart, ICP, E-IC-02, 4.

Evaluation of Positions

The ICP stressed the importance of eliminating the differential between the NR rate and the SP rate. Lauckhart, ICP, E-IC-02, 4. In rebuttal testimony, BPA recovered the regional load charge for NR purchases from the conservation charge, thereby eliminating the differential between the rates. Metcalf, BPA, E-BPA-45R, 4. No adverse comments were made regarding this decision.

Decision

NR purchases, for the purpose of the regional load charge, will be considered a non-BPA load and costs will be recovered through the conservation charge.

Issue #4

How should BPA determine the conservation charge for Period A (November 1983-June 1984)?

Summary of Positions

In rebuttal testimony, BPA established a method to determine the conservation charge for Period A. The proposed method insures that the conservation charge for Period A will be based on the conservation costs, and not overall BPA costs. The scaling factor was to be determined by dividing OY 1984 conservation costs by OY 1985 conservation costs. Metcalf, BPA, E-BPA-45R, 1-2.

Evaluation of Positions

BPA received no comments on the proposed method to determine the conservation charge for Period A. In supplemental testimony, BPA changed the method for determining the revenue requirement for Period A. The new Period A revenue requirement will be calculated as a residual from the FY 1984 revenue requirement. Meyer & Carr, BPA, E-BPA-57, 2-3. BPA will not be calculating an OY 1984 revenue requirement. Therefore, OY 1984 conservation costs will not be available to calculate the conservation scaling factor. FY 1984 conservation costs will be available and include conservation costs for Period A. Thus, BPA should use FY 1984 costs instead of OY 1984 costs to determine the conservation scaling factor.

Decision

The conservation charge scaling factor is based on the ratio of FY 1984 conservation costs to OY 1985 conservation costs.

3. Allocation of Capacity Costs

Introduction

Costs classified to generation capacity must be allocated to BPA firm power customers. Of significant concern in the allocation of capacity costs is the fact that resource capability exceeds peak loads. The costs of the excess resource capability over firm loads must be allocated in an equitable manner that ensures that such costs will be recovered.

Issue #1

Is BPA's proposed method for allocating capacity costs appropriate?

Summary of Positions

In the initial proposal, BPA allocated resource capacity costs by a three step method. First, loads and resources are arranged according to cost allocation priorities in the Regional Act. This step is generally referred to as the 'stacking' approach, and produces a load/resource comparison rather than a load/resource balance. An excess of total capacity resources over total capacity loads is indicated. BPA, E-BPA-5, G-32. Second, BPA identifies the origins of the excess resource capacity with individual resource pools, and achieves a load/resource balance by 'scaling' down the size of resource pools responsible for the existence of the excess resource capacity. BPA, E-BPA-5, G-32. Finally, allocations of resource pool costs to rate pools are developed in a manner identical to the development of energy cost allocations. BPA, E-BPA-5, 42-43.

The DSI's propose the use of a melded capacity rate, contending that the method is easily understandable, readily predictable, involves a minimum amount of subjectivity, and is equitable given the capacity of the system. Schoenbeck, DSI, E-DS-8, 21. The DSI's melded approach to allocating capacity costs would have BPA divide total generation costs classified to capacity by total capacity loads to arrive at a uniform capacity rate. This uniform capacity rate, applied to the loads of each rate pool, would allocate capacity dollars to that rate pool.

As an alternative to the uniformed capacity allocation, the DSI's advocate a stacking approach which uses a separate method to allocate costs of excess capacity. Costs associated with excess capacity resources would be allocated uniformly to all rate classes just as is done implicitly in other utility rate proceedings. Schoenbeck, DSI, E-DS-8, 21.

The PGP also supports a stacking method. The PGP contends that the stacking method reflects the method used in the legislative history of the Regional Act (Appendix B of the Senate Committee Report). They suggest a re-identification of excess capacity such that it would be considered "the Region's surplus capacity." They claim that the stacking method illustrates the Region's available capacity for allocating unrecovered revenue. Garman, et al., PGP, E-PG-01, 11. PGP contends that if BPA projects that it cannot sell a portion of the excess capacity identified after the resources are stacked, then, to the extent the identified capacity resources are unsold exchange resources, those related unrecovered exchange costs may not be allocated to preference customers due to the stipulated settlement in PPC v. Johnson. Garman, et al., PGP, E-PG-06R, 8.

The PPC advocates a stacking method analogous to the method BPA uses to stack energy resources. The PPC maintains that if BPA is unable to market surplus (excess) capacity, the new resources component of cost allocated to that power should be allocated to all customers. They also argue that costs associated with excess unsold exchange capacity should not be allocated to preference customers. Wolverton & O'Meara, PPC, E-PP-01, 12.

APAC also contends that the stacking method should be used to allocate capacity costs. Any excess capacity would be marketed at the fully allocated cost. They believe that to the extent the excess capacity is not sold, the unrecovered costs could be recovered in the post-1985 period as a surcharge under 7(g) or other provisions of the Regional Act, or could be allocated now as was done with unrecovered energy costs. As an alternative, or as a compromise, APAC suggests that BPA adopt the method used in the 1982 final rate proposal. Cook, APAC, E-PA-01, 10-19.

The NWU's recommend a stacking approach which would allocate costs of unsold exchange resources to the DSI's as specified in section 7(c)(2) of the Regional Act. McCullough, NWU, E-NW-02, 7. The WWPUD's suggest that BPA should identify the costs of unsold capacity by increasing the capacity load to match the size of the unsold capacity resources, and allocating costs to it. Once the costs were identified, WWPUD's believe the costs should be assigned in the same manner as the surplus energy deficiency. Under the WWPUD's method the costs of unsold exchange capacity would be allocated to the DSI's and the costs of unsold New Resources capacity would be allocated to all other customers. Hutchinson, et al., WWPUD, E-WW-01, 21.

Several parties argue that if BPA is going to first identify the machine capability of capacity resources, and then scale down the size of resource pools to achieve a load/resource balance, all resource pools should be scaled down uniformly. McCullough, NWU, E-NW-5, 7; Cook, APAC, E-PA-1, 18; Opening Brief, PP&L, B-PL-01, 1-6.

Finally, the PPC, PGP, WWPUD's, and APAC argue that exchange capacity resources are not needed to serve priority firm customers' projected capacity loads because the machine capability of Federal base system resources exceeds priority firm power customers' projected capacity loads. These parties contend that BPA's allocation of capacity costs violates section 7(b)(1) of the Regional Act and the stipulated settlement in PPC v. Johnson. Opening Brief, PPC, B-PP-01, 7-9; Opening Brief, PGP, B-PG-01, 12; Opening Brief, WWPUD, B-WW-01, 12; Opening Brief, APAC, B-PA-01, 74.

Evaluation of Positions

The Administrator has broad discretion in allocating generation capacity costs and designing rates for the sale of peaking capacity. 16 U.S.C. §839e(e) (Supp. V 1981). BPA has chosen to follow the load resource pools scheme, as delineated in sections 7(b), 7(c), and 7(f) of the Regional Act, to allocate generation capacity costs. BPA starts by identifying the machine capability of Federal resources on a monthly basis, and then compares monthly capability with monthly capacity loads. Although BPA can identify the machine capability of its resources, BPA has not identified the portion that is marketable, or even usable. Fuqua, BPA, TR 4140-42; Carr, BPA, TR 4978-80; Fuqua, BPA, TR 4140-42; Carr, BPA, TR 4978-80, 4994-95. There are various ways to determine the amount of capacity on the system, and risk analysis must be undertaken to determine the amount of capacity that is prudent to sell. Fuqua, BPA, TR 4141. See Chapter II, Preliminary Issues. The capacity identified in the COSA as a starting point for allocating capacity costs is not the amount of capacity BPA has determined is saleable, but is simply monthly machine capability. Carr, BPA, TR 5000.

The DSI's suggestion that BPA allocate capacity costs uniformly by dividing total generation capacity costs by total generation capacity loads is easily understandable, readily predictable, minimally subjective, and quite simple. Schoenbeck, E-DSI-8, 21. However, this method would tend to destroy the identity of rate pools. 1982 Administrator's Record of Decision, 71-72. BPA believes that it is preferable to use a method that tracks resource pool costs to the rate pools, and yet achieves an equitable allocation of costs.

The stacking method suggested by several parties is deficient because it does not examine the origins of identified excess capacity. It assumes that excess capacity originates from the resource pools identified in the 'stack' of resources which are at the end of the stack (see BPA, E-BPA-5, G-32). The flaw in the stacking approach is that it equates machine capability with marketable capacity, and thus assumes that all machine capability that exceeds capacity loads is unsold marketable capacity. No party has presented evidence on the record that the entire amount of what has been identified as excess capacity can be sold in the test year. Allocating costs on the basis of an assumption that all such excess capacity can be sold could lead to inequitable results.

In the initial proposal BPA brought capacity loads and resources into balance by scaling down the size of the FBS and New Resources capacity pools. BPA, E-BPA-5, G-32, 35. Several parties have argued that if BPA is going to scale down capacity resources to bring capacity loads and resources into balance, all resource pools should be scaled down uniformly. Cook, APAC, E-PA-01, 15; Wood, ICP, TR 9035. This method was adopted by BPA in the 1982 Wholesale Rate Proposal. 1982 Administrator's Record of Decision, 69-72. However, further analysis relating to the origin of excess capacity indicates that this method is no longer appropriate for allocating capacity costs. Carr & Revitch, BPA, E-BPA-28, 17-19.

In the 1982 Record of Decision, the Administrator stated:

> . . . I do believe that responsibility is borne by the exchange resources for a contribution to the amount of excess resource capacity. BPA has little control over the availability of exchange resources, either for energy or capacity, and for this reason I believe it prudent that the Exchange bear some responsibility for providing excess capacity as do the Federal Base System and new resources pools." 1982 Administrator's Record of Decision, 72.

In the 1983 rate proceeding, BPA has tested the assumption that all resource pools contribute to the existence of excess machine capability. Based on the record, BPA finds that the exchange resource makes no contribution to excess machine capability shown in BPA's capacity loads and resources. Carr & Revitch, BPA, E-BPA-28, 18. The amount of excess machine capability does not change if the exchange loads and resources are included in, or remove from, the capacity load and resource comparison.

BPA has not attempted to quantify the physical peaking capability which exists on the systems of exchanging utilities. Revitch, BPA, TR 5005. BPA assumes that the exchanging utilities have physical peaking capability in excess of total loads. Carr, BPA, TR 5004. Excess physical peaking capability of exchanging utilities is not accounted for in BPA's method of allocating capacity costs. BPA's loads and resources show exchange capacity resources equivalent to exchange capacity loads. BPA, E-BPA-5, G-32-33. Therefore, it is assumed that exchange capacity resources shown in BPA's loads and resources have not been scaled to account for excess machine capability prior to inclusion in BPA's cost allocation loads and resources. Costs of excess machine capability on the systems of exchanging utilities remain in BPA's cost of exchange resources.

Section 7(b)(1) of the Regional Act provides that if Priority Firm customers' loads exceed Federal base system resources, rates applicable to the priority firm customers shall recover the costs of additional electric power needed to supply such loads, first from exchange resources then from new resources. BPA's capacity allocation method comports with the provision of section 7(b)(1) because priority firm customers' loads exceed properly sized capacity resources.

The PPC and the PGP argue that exchange resources are not needed to serve priority firm customers' capacity loads because the machine capability of Federal base system resources identified by BPA in the first step of the allocation process exceeds priority firm customers' capacity loads. Opening Brief, PGP, B-PG-01, 12; Opening Brief, PPC, B-PP-01, 6. Their argument ignores the fact that the machine capability identified in the first step of the allocation process is not the quantity of capacity BPA knows is marketable, or even usable, to meet firm loads in the test period. Fuqua, BPA, TR 4140-42. While BPA has not quantified the amount of capacity that is marketable, it would not be prudent to assume for purposes of determining rates that all machine capability is marketable capacity. See Chapter II, Preliminary Issues. If BPA adopted the approach suggested by the PGP and the PPC, BPA's initial allocation would not allocate all the capacity costs BPA has incurred in order to meet its firm power customers' loads. This would be a questionable allocation of costs.

The PGP and the PPC also argue that BPA's allocation is in violation of the stipulated settlement in PPC v. Johnson. Opening Brief, PPC, B-PP-01, 7-9; Opening Brief, PGP, B-PG-01, 12. The Stipulated Settlement provides:

> Any costs. allocated in accordance with section 7(g) of P.L. 96-501, due to the sale of or inability to sell prior to July 1, 1985, excess electric power acquired under Section 5(c)(2) of P.L. 96-501 shall not be allocated to the rates for the general requirements of public bodies, cooperatives and Federal agencies. (emphasis added).

BPA's allocation of capacity costs is not an allocation of costs of excess electric power in accordance with section 7(g) of the Regional Act. Therefore, the stipulated settlement in PPC v. Johnson has no bearing on this issue.

BPA's identification of excess capacity, and costs thereof, is specific to resource pools. The scaling process to achieve load/resource balance allocates all costs of all resource pool capacity to all loads. Among loads which are allocated capacity costs are surplus firm power loads. In the Wholesale Power Rate Design Study, a portion of the costs allocated to surplus firm power loads are assumed to be unrecovered costs due to an inability to sell such power. BPA, E-BPA-7, 22. The fully allocated exchange resource cost of $100.969 million includes capacity costs allocated through the COSA. None of the allocated costs that BPA projects it will be unable to recover as a result of an inability to sell surplus firm power in the test year have been allocated to the preference customers. Thus, BPA has complied with the stipulated settlement. The PPC and PGP's interpretation of the stipulated settlement requires ignoring the phrase "in accordance with section 7(g)." A contract must be interpreted to give meaning to all its express terms. Washington Metropolitan Area v. Mergertime Corporation, 626 F.2d 959 (D.C. Cir. 1980).

Decision

The method proposed by BPA in the initial proposal, which scales only Federal resource pools to achieve a capacity load/resource balance, recognizes both operational and transactional features inherent in BPA's loads and resources. Therefore, it results in an equitable allocation of capacity costs including costs associated with excess resource capacity. This method is adopted for BPA's final rate proposal.

4. Allocation of Fish and Wildlife Costs

Issue #1

Should BPA's fish and wildlife costs be allocated to all BPA customers?

Summary of Positions

In the initial proposal, BPA allocated fish and wildlife costs only to firm power customers receiving an allocation of the costs of FBS resources. BPA believes that these costs are directly related to the Federal hydro system. Costs incurred to mitigate the damage to fish and wildlife caused by Federal dams on the Columbia River should be charged only to the beneficiaries of those dams, and not to all BPA customers. Carr & Revitch, BPA, E-BPA-28, 6.

The PPC proposes that fish and wildlife costs should be allocated to all users of power. They argue that all BPA customers benefit from the existence of the Federal Columbia River Power System. They also argue that everyone benefits from the expenditure of money to protect, mitigate, and enhance fish and wildlife. Wolverton & O'Meara, PPC, E-PP-01, 13-16. Additionally, the PPC indicates that fish mitigation programs have external benefits that flow to others besides the owners and operators of Federal Dams. Wolverton & O'Meara, PPC, E-PP-02R, 12. PPC contends that BPA is required by the Regional Act to allocate fish and wildlife cost to all power users. Opening Brief, PPC, B-PP-01, 10-16. PPC argues that their allocation proposal is consistent with BPA's allocation of fish and wildlife costs in 1981. Opening Brief, PPC, B-PP-01, 15-16.

APAC claims that fish and wildlife costs, more than any other costs, are clearly attributable to the Regional Act. They claim that for BPA to allocate no fish and wildlife costs to the DSI's is not equitable or warranted, given the fact that all customer classes benefit from the existence of the Federal hydro system. APAC suggests that it is appropriate to remove the fish and wildlife costs from the resource pool analysis and allocate them as an overhead expense to all firm loads. Cook, APAC, E-PA-01, 22.

Evaluation of Positions

The Federal Columbia River Power System hydroelectric projects are defined in the Regional Act as Federal base system resources. 16 U.S.C. §839a(10) (Supp. V 1981). Section 7(g) of the Regional Act instructs the Administrator to "equitably allocate in accordance with generally accepted ratemaking principles and the provisions of this Act" all costs and benefits not otherwise allocated by the Regional Act, including "fish and wildlife measures." 16 U.S.C. §839e(g) (Supp V 1981). Section 7(b)(1) of the Regional Act directs the Administrator to allocate FBS resource costs first to priority firm customers.

BPA's fish and wildlife expenditures in the test period are an internalization of external costs associated with the hydroelectric facilities. Carr, BPA, TR 5214-5216. These expenditures are much like the costs a utility incurs at a coal-fired thermal generating facility to internalize atmospheric pollution costs the facility would impose on society in the absence of pollution control devices. Carr, BPA, TR 5214-15. It is standard utility practice to allocate to the customers that purchase power from a generating facility the costs of pollution control devices at that facility.

BPA acknowledges that in the 1981 Record of Decision, the Administrator allocated fish and wildlife costs to all power users. 1981 Record of Decision, VI-19. However, the 1981 Record of Decision noted that in 1981, when the Regional Act was in its nascent stage, BPA "anticipated that at least a portion of the expense associated with fish and wildlife may be directed toward programs which are unrelated to the effects of hydro plants." Id. BPA went on to state:

> "As the programs for which these expenses are incurred become better defined, it may be possible to develop a more disaggregated allocation of these costs for future rate filings." Id.

Fish and wildlife program expenditures for fiscal years 1984 and 1985, which are included in the OY 1985 revenue requirement, are confined to mitigating the effects on fish and wildlife caused by the hydroelectric facilities on the Columbia River and its tributaries. Palensky, BPA, E-BPA-20, 4. Since it is now possible to identify the specific purposes of the fish and wildlife expenditures, those costs should be allocated to the customers that are the assured beneficiaries of the Federal hydro system. While other power purchasers may benefit from the nonfirm energy generated by the federal hydro system, for purposes of cost allocation only customers allocated the costs of Federal base system resources are assured beneficiaries of BPA's low cost hydro resources.

Decision

Test period BPA fish and wildlife expenditures are confined to mitigating the effects on fish and wildlife caused by hydroelectric facilities on the Columbia river and its tributaries. Since the fish and wildlife costs are mitigating impacts on Columbia river fisheries caused by the hydroelectric system, BPA believes it is reasonable to allocate all fish and wildlife costs in the test period to firm power purchasers that are allocated the costs of Federal base system resources.

5. Allocation of BPA 'Other' Generation Costs

Issue #1

Should BPA allocate its 'other' generation costs to all loads?

Summary of Positions

In the initial proposal BPA allocated 'other' generation costs to all loads. BPA, E-BPA-5. These costs are administrative and general costs, research and development costs, contributions to the Electric Power Research Institute (EPRI), and other overhead costs. Such costs are not identifiable with the cost of specific resource pools, and therefore are allocated to all customer classes independently of the allocation of resource pool costs. BPA, E-BPA-5, G-4.

The DSI's have identified cost items amounting to approximately $30 million included in 'other' generation cost, which they claim can be properly identified as administrative costs of the Federal base system. Schoenbeck, E-DSI-8, 13-14. These costs relate to activities of BPA's Offices of Engineering and Construction, Regional Operations, and Power and Resources Management. Other costs which the DSI's have identified as FBS costs included lease payments for hydro storage fees ($13.2 million). The DSI's claim that approximately $6 million included in other generation costs related to resource acquisitions, resource options, and preconstruction assistance should be identified as costs of BPA's New Resources pool. The DSI's claim that aside from errors made by BPA staff, the allocation of BPA 'other' generation costs constitutes a double allocation of such costs to them in particular, and indeed to all loads served, for cost allocation purposes, by exchange resources. They claim that the costs of the exchange resource include overhead costs incurred by the exchanging utilities and that BPA's allocation of similar costs incurred by BPA allocates to them more than their fair share of the region's overhead costs. Consequently, other BPA ratepayers are allocated less than their fair share of such costs. Schoenbeck, DSI, E-DSI-8, 13-16.

The NWU's argue that it is appropriate for BPA to not only allocate BPA overhead costs to loads served, for cost allocation purposes, by exchange resources (including the DSI's) but other costs as well, and that DSI 'double counting' arguments are groundless. McCullough, NWU, E-NW-5, 1-4.

Evaluation of Positions

Overhead costs incurred by a business are generally not identifiable with any specific costs of a product or service provided by the business. It is an accepted cost accounting practice to charge overhead to all products and services sold by the business. BPA's overhead costs are allocated in a manner consistent with this cost accounting practice. BPA, E-BPA-5, G-4 & G-9. Overhead costs included in the average system cost of exchange resources are related specifically to the exchange resource pool. The DSI's claim that BPA overhead costs are specifically identifiable with either the FBS or the New Resources pool is unfounded. BPA's Offices of Engineering and Construction, Regional Operations, and the Office of Power and Resources Management perform activities related to all resource pools and to all customer classes. BPA's top management performs an administrative function that relates to all BPA resources and all customer classes. Costs incurred for these activities fall clearly into a category of overhead costs. Such overhead costs are allocated over all loads because they are not specific to any of BPA's resource or rate pools. BPA, E-BPA-5, G-4, G-9.

Decision

In the final proposal, BPA allocates "other" generation costs to all loads. These costs are related to all BPA resources and customer classes. Therefore, it is appropriate to allocate the costs to all loads independent of the resource pool cost allocations.

6. Allocation of Cash Lag

Issue #1

Is BPA's allocation of cash lag appropriate?

Summary of Positions

In the initial proposal BPA functionalized, segmented, classified, and seasonally differentiated its revenue requirement for cash lag on the basis of the functionalization, segmentation, classification and seasonal differentiation of all other costs except conservation. The cash lag was then allocated to all customers on the basis of their loads relative to total loads. Carr & Revitch, E-BPA-28, 2-31.

The DSI's argue that BPA's allocation of the cash lag is inappropriate for two reasons. First, they claim the DSI's are not responsible for BPA's cash lag because they are served entirely from exchange resources. They claim that the cash flow effect on BPA from the exchange transaction reduces the overall cash lag requirement because BPA receives payment from the DSI's prior to paying the invoices of exchanging utilities. Schoenbeck, DSI, E-DS-8, 16. They claim that because the exchange transaction has a positive effect on BPA's cash flow, none of the cash lag should be allocated to loads served by exchange resources. Second, the DSI's argue that BPA's allocation of cash lag to them constitutes a double allocation of cash requirements. They point out that through the average system cost of exchange resources they pay for cash working capital requirements of the exchanging utilities. Allocation of BPA's cash requirement in addition to that in the ASC constitutes 'double counting'. Schoenbeck, DSI, E-DS-8, 16-17; Opening Brief, DSI, B-DS-01, 65.

Evaluation of Positions

BPA's cash lag relates to the differences in timing of receipts of revenue and disbursements of cash. BPA, E-BPA-5, G-15. The receipts of revenue can be directly traced to any individual customer class. However, the disbursements of cash cannot be traced directly to any individual customer class. BPA disburses cash to cover costs related to service to all customers. The DSI's may pay their electric bills faster than BPA pays its bills for exchange resources, but the DSI's are not the only customers for which BPA incurs exchange resource costs. BPA, E-BPA-5, G-24, 32, 33. Nor are exchange resource costs the only costs allocated to the DSI's. BPA, E-BPA-5, 34-36. In order to specifically identify the responsibility for the cash lag by customer class, it would be necessary to perform an extensive analysis which relates all cash disbursements to specific customer classes. This is not a common practice in the utility industry.

Decision

BPA's cash lag is a revenue requirement which reasonably can be allocated to all customer classes. Such costs cannot be identified with specific rate classes. The argument made by the DSI's that BPA's cash flow is enhanced because the DSI's pay their electric bills prior to BPA's payment for exchange resources may be correct, but their argument is incomplete. The timing of all other cash transactions must be analyzed in order to reach a full accounting of customer class responsibility for the cash lag. The DSI's have performed a partial accounting for the cash lag, as it relates to their responsibility for BPA's cash lag. Without a full accounting of customer class responsibility, to exempt the DSI's or loads served by exchange resources from allocation of the cash lag would leave BPA in a position whereby the cash lag logically would be allocated as an overhead cost to all other customers. Since all BPA customers share in responsibility for the cash lag, it is equitable that all BPA customers be allocated the costs associated with BPA's cash lag.

7. Allocation of Fringe Transmisson Costs

Issue #1

Is BPA's method for allocating fringe transmission costs appropriate?

Summary of Positions

In the initial proposal BPA allocated costs of the fringe transmission segment to all customer classes who use the network transmission segment plus CSPE wheeled power. BPA, E-BPA-5, 45. The latter class is allocated fringe transmisson costs because it is an intra-regional transaction serving a multitude of utilities. With this exception, the loads assumed to be served from the fringe segment for the development of cost allocation percentages are identical to loads that customer classes place on the network segment.

The DSI's contend that BPA's method for allocating fringe transmission costs is inequitable. They point out that only one DSI customer receives fringe service and its corresponding load is considerably lower than the 450 megawatts BPA used in developing the allocation of fringe segment costs to the DSI's. The 450 megawatts used for this allocation represents BPA's estimate of service to the DSI top quartile load. The DSI's suggest that BPA consider only the actual load placed on the fringe segment by the DSI users, and that use of the entire DSI top quartile load for purposes of cost allocation places a disproportionate burden on the DSI's for payment of costs of that BPA transmisson segment. Schoenbeck, DSI, E-DS-8, 8-9.

Evaluation of Positions

An examination of descriptions in the record of the integrated network and fringe transmission segments, BPA, E-BPA-5, 3, 4, indicates that the fringe transmission segment performs functions that are similar to the functions of the network transmission segment. The fringe segment includes those facilities which generally are needed only to serve Federal power customers. BPA, E-BPA-5, 4. The location of facilities of the fringe segment therefore depends to a large extent on the physical location of network transmission facilities in relation to loads BPA must serve.

BPA incurs combined fringe and network costs to meet its total power sales loads. BPA, E-BPA-5, E-3-4. However, there is little information in the record to demonstrate cost causation between a single power sales load and the cost of the segment directly serving that load. For example, if a particular load currently served directly from the network was instead located in an area currently served by the fringe, then BPA's criteria for constructing the transmission system would have been different. Since the mixture of fringe versus network costs would likely be different, BPA's total transmission costs also would be different. However, it is not clear if the total costs would be greater or less than currently projected. This occurs because, in this example, the lowest cost alternative might have been to extend the network (instead of the fringe), thus increasing total network costs while reducing fringe costs. Alternatively, service from an enhanced fringe might have been the lowest cost option, leading to increased fringe costs and reduced network costs. In either case, the combined fringe and network costs could be either higher or lower, depending on the particular situation. This example illustrates the difficulty in associating cost causation of a particular segment with power sales loads served from that segment for a utility obligated to provide reliable transmission service to all of its power sales loads.

Decision

In providing service to power sales loads, BPA's cost causation for construction of the fringe segment is indistinguishable from the cost causation underlying construction of the network. Therefore, it is appropriate to allocate fringe segment costs on the basis of loads that customers place on the network segment.

8. Inclusion of Exchanging Utilities in the "Deemed Equal" Status in the COSA Load/Resources Balance

Issue #1

Is it proper to include in the COSA load/resource balance the loads and resources of exchanging utilities that are projected during the test year to be "deemed equal" pursuant to section 10 of the Residential Purchase and Sale Agreement?

Summary of Positions

Section 10 of the Residential Purchase and Sale Agreement provides that utilities may elect to have their average system cost deemed equal to BPA's Priority Firm rate. Contract No. DE-MS79-81BP9. Exchanging utilities deem equal when their average system cost is less than BPA's Priority Firm rate. Absent the deemed equal provision, pursuant to section 5(c) of the Regional Act these utilities would pay BPA the net of the difference between their average system cost and BPA's Priority Firm rate. Once a utility "deems equal," BPA makes no further payments to the utility unless the utility elects to resume full participation.

The "deemed equal" provision of the contract allows utilities to rescind the election to be deemed equal and resume participation in the exchange. The utility cannot resume participation until its exchange account is brought back into balance. Therefore, during the time the utility is in the "deemed equal" status, BPA keeps an account as if the exchanging utility was selling BPA power at its average system cost, and BPA was selling the utility power at the Priority Firm rate. The net balance in the account accumulates interest.

In the initial proposal for purposes of allocating cost, BPA included the loads and resources of exchanging utilities projected to be in the "deemed equal" status in the COSA load/resource balance. BPA, E-BPA-5, G-23. These loads and resources are included in the COSA load/resource balance because the exchanging utilities accrue the liability to BPA for 'negative' exchange benefits while in the "deemed equal" status. The account must be brought into balance before the utility can resume receiving the monetary benefit of the exchange.

The PPC argues that utilities projected to be in the "deemed equal" status during the test period should not be included in BPA's COSA load/resource balance. Their argument relies on the fact that no cash transaction takes place between BPA and a utility in the deemed equal status. Wolverton & O'Meara, PPC, E-PP-01, 20. They point out that a utility that exchanges for a short time, and then elects to be deemed equal, can have substantial long-term effects on BPA's cost allocation loads and resources. They indicate that the technique provided for in exchange contracts for repayment of negative benefits increases rate stability when deemers are excluded from BPA's COSA load/resource balance. Wolverton & O'Meara, PPC, E-PP-01, 19-22.

The WWPUD's also argue that loads and resources associated with utilities projected to be in the "deemed equal" status should be excluded from BPA's COSA load/resource balance. The WWPUD's argument relies on the fact that no cash transaction takes place between BPA and a utility in the "deemed equal" status. Hutchison, et al., WWPUD, E-WW-01, 16. They argue that Priority Firm customers are penalized by BPA's inclusion of deemed exchange loads in 7(b) loads, and deemed exchange resources in BPA's exchange resource pool, because the costs of relatively more exchange resources are allocated to the Priority Firm customers' rate pool. The WWPUD's argue that the exclusion of deemers from BPA's loads and resources would bring ratesetting closer to actual system operations and post-1985 ratemaking would be simplified. They assert that exclusion of the deemed exchange would reduce the proposed PF rate by 18 percent.

Evaluation of Positions

For ratemaking purposes BPA treats the exchange as a resource transaction. The exclusion of loads and resources of utilities projected to be in a "deemed equal" status from BPA's COSA load/resource balance would be equivalent to treating the deemed exchange as an 'accounting' transaction, and the nondeemed exchange as a 'resource' transaction. Because exchange costs and participation in the exchange is projected for a future test period, exclusion of deemers from BPA's loads and resources would cause BPA to have a financial need to project which utilities in the "deemed equal" status would resume participation in the exchange. Hutchison, WWPUD, TR 6481. The consequences of estimation errors could be underrecovery of costs. The WWPUD's concede that exclusion of deemers from BPA's load/resource balance might result in harm to BPA's rate continuity and rate stability because if a utility alternates between deemer and non-deemer status, loads will oscillate. Hutchison, et al., WWPUD, E-WW-02R, 15.

Decision

The COSA load/resource balance should include the loads and resources of exchanging utilities that are projected during the test year to be "deemed equal" pursuant to section 10 of the Residential Purchase and Sale Agreement. The exchanging utilities that are deemed equal still accrue a liability to BPA under terms of the exchange contract. Since this account is kept during the "deemed equal" period, it is appropriate to assume for ratemaking purposes that the exchange mandated by section 5(c)(1) of the Regional Act continues during the deemed equal period. The utility must balance the exchange account before it can resume exchanging, so the exchange of resources has not actually ceased during the "deemed equal" period. BPA has simply contractually agreed to forgo the right to collect the positive net value during the "deemed equal" period. Therefore, the exchange transaction is still operative.

Hence, the utilities projected to be in the deemed equal status should be included in BPA's load/resource balance to reflect the continuity of the exchange transaction. The record demonstrates that in the final proposal only one utility is in the "deemed equal" status. Therefore, any impact on costs allocated to 7(b) customers due to inclusion of deemers is minimized.

9. Deferral

Issue #1

Should BPA allocate costs of its deferral on the basis of a specific identification of certain classes which contributed to BPA's deferral?

Summary of Positions

BPA allocates costs associated with deferred payments to the Treasury to all customers on the basis of loads. BPA, E-BPA-5, G-15. BPA has not specifically identified customer classes responsible for the deferral, and has no basis on which to base a customer specific allocation of deferral costs. Carr & Revitch, BPA, E-BPA-28, 4-5. Costs associated with the deferral relate to BPA's underrecovery of costs in the past. BPA plans, operates, and incurs cost on the basis of forecast conditions. Any allocation method based on an examination of historical conditions may not reflect the reasons why costs were incurred. BPA's ratemaking process does not hold individual customers accountable for historical cost overrecoveries or underrecoveries resulting from deviation of actual results from forecast costs or loads in past rate cases. Carr & Revitch, BPA, E-BPA-28, 5.

The PPC contends that BPA can and should identify responsibility for deferral on a customer by customer basis. Opening Brief, PPC, B-PP-01, 25. The PPC argues that BPA has an obligation under sections 7(c)(1)(a) and 7(b)(3) of the Regional Act and General Contract Provision 8 of the Power Sales Contracts, and the stipulation for settlement in PPC v. Johnson, Ninth Circuit No. 81-7806 to charge the DSI's for the underrecovery of revenues due to their actual loads falling below forecast loads. The PPC claims that underrecovery is the cause of the deferral. Therefore, the PPC claims, BPA must allocate the deferral using causation principles and cannot refuse to do so because it would be complicated and controversial. Opening Brief, PPC, B-PP-01, 26.

The PGP suggests that BPA is statutorily obligated to allocate the unrecovered exchange cost deferral from previous years on a cost basis. Opening Brief, PGP, B-PG-01, 10.

Evaluation of Positions

The deferral was caused not solely by the DSI's, but by all customer classes. Any identification of past underrecovery of costs from the DSI's would necessitate a full comparison of all actual versus forecast data used in setting rates for all customers under previous rates. This would also necessarily entail the identification of underrecovery of costs not only from the DSI's but all other customers. BPA has not developed a methodology to specifically identify underrecoveries by customer classes which contributed to BPA's accumulated deferral. Such a methodology would be extraordinarily complicated and would use controversial assumptions. Carr & Revitch, BPA, E-BPA-28, 4.

BPA proposes to recover the amount of its deferral by allocating across all rate classes. BPA, E-BPA-28, 2-3. The PGP and the PPC (hereinafter PGP) argue that sections 7(b)(3) and 7(c)(1)(A) of the Regional Act require BPA to allocate the unrecovered exchange cost deferral from previous years on a cost basis and to identify and allocate such costs to the responsible customer classes. Opening Brief, PGP, B-PG-01, 10; Opening Brief, PPC, B-PP-01, 25-26. It is presumed that the PGP intends by this language that BPA must allocate to the DSI's the portion of the overall deferral which has been caused by an underrecovery of net residential exchange costs resulting from DSI load underruns.

Assuming that the portion of the deferral attributable to the DSI load underruns causing underrecovery of the net costs of the exchange can be currently identified with reasonable accuracy, the question remains as to whether the Administrator is required to allocate that amount of the deferral to the IP-83 rate for recovery prior to July 1, 1985. Section 7(b)(3) itself does not require deficiencies in the collection of the net costs of the residential exchange resulting from DSI load underruns to be recovered prior to July 1, 1985. The plain meaning of that section is that such recovery may only occur after July 1, 1985, because of its reference to a "net revenue surplus or deficiency occurring for the period ending June 30, 1985," and its direction that "any such revenue deficiency . . . shall be recovered . . . after July 1, 1985." Indeed, there will be no "net revenue surplus or deficiency occurring for the period ending June 30, 1985," until July 1, 1985.

As stated above, the PPC also argues that section 7(c)(1)(A) of the Regional Act requires BPA to assess the DSI's, in the rate prior to July 1, 1985, the full amount of any unrecovered net exchange costs arising out of earlier DSI load underruns. Opening Brief, PPC, B-PP-01, 26. Section 7(c)(1)(A) states:

> The rate or rates applicable to direct service industrial customers shall be established --
>
> (A) for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient to recover the cost of resources the Administrator determines are required to serve such customers' load and the net costs incurred by the Administrator pursuant to section 5(c) of this Act, based upon the Administrator's projected ability to make power available to such customers pursuant to their contracts, to the extent that such costs are not recovered through rates applicable to other customers . . . .

The language of section 7(c)(1)(A) is not distinctive in comparison to the other ratemaking sections of the Regional Act on the subject of retroactive recovery of costs from the responsible class. Indeed the language of section 7(c)(1)(A) is not as suggestive of such retroactive cost recovery as is the language of section 7(b)(1) for the Priority Firm rate. Section 7(b)(1) states:

> Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power acquired by the Administrator under section 5(c) and then from other resources. (emphasis added)

In contrast, section 7(c) merely states that the rates for DSI customers "shall be established - (A) for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient" to recover resource costs and the net costs of the exchange (emphasis added). It has not been suggested that the Administrator must engage in retroactive cost recovery in developing the 7(b) rate. There is even less basis to argue that the statutory language of section 7(c)(1)(A) requires retroactive cost recovery in developing the DSI rate. The direction to recover the net costs of the exchange "to the extent that such costs are not recovered through rates applicable to other customers" refers to the direction in section 7(b) to first use the exchange resource to serve the 7(b) load growth after the Federal base system can no longer serve it. The language of this directive is no stronger than the 7(b)(3) language in implying a requirement to recover underrecoveries from a particular "responsible class."

The most logical interpretation of the intent of Congress, based solely on the language of the statute, is that (1) the DSI rate was to be established on the same prospective basis as all of the other rates; and (2) only section 7(b)(3) was intended to recover any underrecoveries of the net cost of the exchange resulting from DSI load underruns. The contrary PGP position necessarily implies that, pursuant to section 7(b)(3), the DSI's would share with other customer classes (other than the 7(b) class) only the obligation for such underrecoveries as occur in the last rate period prior to July 1, 1985. There is, however, no mandate in the Act to institute any particular number of rate proceedings prior to July 1, 1985. Therefore, the PGP view requires the conclusion that the Administrator could impose all of the net exchange cost underrecoveries related to DSI load underruns either on all customers (other than 7(b) customers), by having only one rate period prior to July 1, 1985, or primarily on the DSI's by having multiple rate periods prior to July 1, 1985. Additional indication of such momentous and unguided discretion is not found anywhere else in the Act.

A statement included in the legislative history of the Regional Act is instructive as to the early interpretation given to section 7(c)(1)(A). Exhibit B to the Senate Report on S.885, Report No. 96-272, was written by BPA to aid the Senate Committee to compare wholesale power rates of the various regional customers under the proposed legislation. It is therein stated that, under section 7(g), a "(r)ate adjustment associated with the difference between the revenues from _all_ sales and the cost of resources required for such sales" would be "applied to _all_ firm power sales _under any rate_." _Id_. at 60 (emphasis added). That is, rather than ratemaking which would assess any particular class with the revenue underrecoveries associated with the power purchasing activities of that class, the understanding was that the costs of all such underrecoveries would be spread throughout all the rates. No exception was made for any underrecoveries associated with the DSI's. Ultimately, protection of the preference customers from significant load underruns and the consequent flow of unrecovered net exchange costs to their rates resulted from the addition of section 7(b)(3), i.e. an express mandate to engage in retroactive ratemaking after July 1, 1985, rather than a change in section 7(c)(1)(A) to change its prospective character.

Decision

BPA does not expect to know the net revenue surplus or deficiency occurring for the period ending June 30, 1985, until after June 30, 1985. No suggestions are made in legislation that BPA must engage in retroactive cost recovery with respect to establishing DSI rates prior to July 1, 1983. Therefore, no requirement exists in this rate adjustment to specifically identify with customer classes the costs associated with BPA's deferral. BPA's allocation methodology for the deferral is correct and appropriate.

CHAPTER VI

WHOLESALE POWER RATE DESIGN STUDY

A. Introduction

The Wholesale Power Rate Design Study (WPRDS) is the final step in the development of BPA's wholesale power rates. In this study, results of the COSA are modified to reflect BPA's rate design objectives, to comport with contractual requirements, to reflect the results of other BPA studies, and to comport with applicable legislation. BPA's costs, modified as described above, are then divided by the applicable billing determinants to determine BPA's wholesale power rates.

B. Adjustments

BPA makes a number of adjustments to the results of the COSA in order to derive the final wholesale power rates. These adjustments include treatment of: (1) excess revenues; (2) fixed contract revenue deficiencies; (3) the value of reserves credit; (4) the surplus firm power revenue deficiency; (5) equalization of demand; and (6) the Hanna discount. Issues related to each of these adjustments are discussed in this section.

1. Excess Revenues

Excess revenues are generated when revenues exceed allocated costs. There are five sources from which BPA receives "excess revenue." BPA credits these excess revenues to other customer classes, thereby effectively reducing the allocated costs so that BPA does not overcollect its revenue requirement. There are two issues related to excess revenues. The first, classification, is discussed in the classification section. The second, revenue estimation is presented in the section entitled "Surplus Firm Power Revenue Deficiency."

2. Fixed Contract Revenue Deficiencies

BPA is unable to increase the charges associated with certain contracts to cover today's costs of providing those contractual services, and, therefore, BPA experiences "revenue deficiencies."

Also, Capacity/Energy Exchange contracts result in a revenue deficiency because capacity costs are allocated to this class but the payment for the capacity is in the form of energy. Other customer classes are allocated the revenue deficiency so that BPA can meet its overall revenue requirement.

Issue #1

How should revenue deficiencies from fixed contracts and the capacity/energy exchange be allocated?

Summary of Positions

BPA's intitial proposal assigned revenue deficiencies resulting from Canadian Treaty fixed contracts to loads served by the FBS (customers purchasing under the PF and CF rate schedules). Deficiencies resulting from Capacity/Energy Exchange contracts are assigned to the PF class. BPA, E-BPA-7, 14-17; Metcalf, BPA, E-BPA-32, 5.

Prefiled testimony by APAC contended that the revenue deficiency should be recovered from all customers except the fixed contract customers. Cook, APAC, E-PA-02, 59. This position was supported by PGP. Garman, et al., PGP, E-PG-06R, 28-29. Subsequent testimony from APAC stressed that the revenue deficiencies should be recovered from all customers, but no mention was made of excluding fixed contract customers. Garten, APAC, TR 9128-9129; Opening Brief, APAC, B-PA-01, 83; Reply Brief, APAC, R-PA-01, 28.

Evaluation of Positions

The Canadian Treaty and Capacity/Energy Exchange agreements expand and enhance the capacity and energy of the Federal base system and, therefore, the associated costs should be assigned to the FBS. The users of the FBS, the PF and CF customers, appropriately would pay for the costs that result from improvements to the FBS resource pool. BPA, E-BPA-7, 15; Metcalf, BPA, E-BPA-32, 5.

APAC states that the fixed contract revenue deficiencies should be allocated to all customers because all customers benefit if the FBS is enhanced. For example, FBS enhancement (1) assists DSI first quartile service; (2) permits capacity sales to IOU's; (3) benefits IOU's that purchase under the WNP-1 agreement; (4) increases the availability of surplus power to California utilities; and (5) helps the Water Budget. Cook, APAC, E-PA-02, 59; Opening Brief, APAC, B-PA-01, 84-85.

However, none of these points leads to the conclusion that the revenue deficiencies should be allocated to classes other than FBS users:

(1) No evidence is submitted that first quartile service is enhanced. To the extent that the additional storage capability provided by the Canadian Treaty "firms up" nonfirm energy, it may be that service to the first quartile is diminished. Garman, PGP, TR 8216. On the other hand, the storage capability may enhance the system's ability to provide service with provisional drafts. The Capacity/Energy Exchange increases the firm energy capability and decreases the firm capacity capability of the system. Since BPA does not plan firm resources to serve the first quartile, there is no reason to believe that these contracts enhance service to the first quartile.

Even if it were true that first quartile service is enhanced, APAC's conclusion would not follow. To the extent that first quartile service was identified with and allocated costs of the fixed contracts, it would be double counting to also assign the full opportunity cost of that service to the DSI's. A rate can be based on allocated embedded cost or opportunity cost, but not both. Enhanced nonfirm energy sales and first quartile service benefits FBS users by increasing excess revenues allocated to FBS users.

(2) A portion of the revenue deficiency from the Canadian Treaty contracts is allocated to both seasonal and annual firm capacity customers. BPA, E-BPA-7, 71. None of the deficiency from the Capacity/Energy Exchange is allocated to Firm Capacity because that arrangement increases the energy capability of the FBS while reducing the remaining amount of capacity available to sell to other utilities.

(3) IOU's that purchase under WNP-1 agreements pay the PF rate for that power and therefore share in paying the revenue deficiencies.

(4) On a planning basis, neither the Canadian Treaty nor the Capacity/Energy Exchange increases the amount of BPA firm surplus. The enhanced capability provided by those resources is included in BPA's resource planning process. Metcalf, BPA, TR 7326. In any case, APAC's suggestion carried to its logical conclusion would raise, not lower, the Priority Firm Power rate. BPA currently allocates its most expensive resources to surplus firm power based upon the resource stacking method. If, instead, BPA were to identify energy and capacity from the fixed contracts as serving surplus firm power loads, both the costs and resource capability should be assigned to those customers. Since that capability is currently included in the FBS resource, moving it to the top of the resource stack to serve surplus firm power customers would increase the amount of exchange needed to serve the PF load.

(5) To the extent that the fixed contracts assist in accommodating the Water Budget, this reduced the effect of the Water Budget. This results in fewer costs allocated to FBS users, since the Water Budget is modeled as a reduction in FBS capability. BPA, E-BPA-05, Table G-I, G-23.

APAC also points out that non-FBS customers have CSPE and Capacity/Energy Exchange contracts. Opening Brief, APAC, B-PA-01, 25. However, allocation of revenue deficiencies to these customers would deprive them of the benefits of their fixed contracts. Metcalf, BPA, TR 7337-7339. APAC responds that allocating these costs to FBS users deprives them of the benefits of their fixed contracts. Opening Brief, APAC, B-PA-01, 86. However, that is not the case. Priority Firm customers with CSPE contracts continue to receive the full benefits of their fixed contracts. They also receive the benefit and pay the costs of the increased FBS capability brought about by those contracts. Metcalf, BPA, TR 7339-7340; Garman, PGP, TR 8219-8220.

APAC questions whether the Capacity/Energy Exchange contracts benefit BPA customers in view of the 3 mills/kWh which BPA receives for energy when the return of that energy would be spilled. Opening Brief, APAC, B-PA-01, 85. APAC's analysis is incomplete. The Capacity/Energy Exchange increases the firm energy capability of the FBS by 306 average megawatts. BPA, E-BPA-5, G-23. A revenue deficiency of about $50.6 million is created when capacity costs are allocated to the Capacity/Energy Exchange. BPA, E-BPA-7, 61. Thus, even if it is assumed that this capacity were marketable at its fully allocated cost, the Capacity/Energy Exchange would be an 18.9 mills/kWh resource. Removal of these megawatt hours from the load/resource balance would result in the assignment of more expensive exchange costs to Priority Firm.

Finally, APAC argues that allocating these costs to all classes would diversify and minimize BPA's risk of not recovering these costs. Garten, APAC, TR 9127-9128; APAC, Opening Brief, APAC, B-PA-01, 86. APAC overlooks the basic fact that once in the rates, costs are fungible. Diversification of risk is enhanced by spreading total revenue recovery as widely and evenly as possible. Allocation of all cost categories to all classes is no less risky than allocating specific cost categories to specific classes if the final rates are similar. In fact, BPA would diversify its risk by designing rates which are equal to each other. Much of BPA's recent revenue recovery problems have come from load underruns in the IP, NR, and SP rate classes in which customers pay rates greater than the PF rate. Metcalf, BPA, E-BPA-46R, Attachments 1, 3-4.

Decision

The revenue deficiencies from fixed contracts have been allocated to FBS users because those contracts enhance the capability of the FBS. Assignment of those deficiencies to other customer classes would imply that some of the additional resource should also be removed from the FBS and be used to serve other customer classes. This would lead to higher costs allocated to FBS users.

3. Value of Reserves Credit

BPA provides a credit to the DSI's to reflect the value of the system reserves which they provide. The resulting revenue deficiency is allocated to firm power classes of service. Classification of the value of reserves credit is discussed in the classification section.

Issue #1

How much of the value of reserves should be credited to the DSI's for the right to restrict their load?

Summary of Positions

BPA proposed that the credit to the DSI's for the reserves provided by BPA's ability to restrict their loads is based on a share-the-savings concept. First, the value to BPA of having the right to restrict the DSI load is determined. Then, the cost of an outage to the DSI's is calculated. The sum of the value and the cost is divided in half to determine the total amount of the credit. BPA, E-BPA-7, 20.

The DSI's maintained that they should receive the entire value of the reserves they provide. Peseau, DSI, E-DS-10, 33.

Evaluation of Positions

In prefiled testimony the DSI's argued that a share-the-savings approach was inappropriate. They claim that in valuing the reserves provided by the DSI restriction rights, BPA looks at the least cost alternative. The DSI's assert that this results in assigning a value to the reserves provided by the

DSI restriction rights equal to the cost of the alternatives. Crediting the DSI's for the entire value of the reserves, the DSI's conclude would cause the other customers to be no worse off than if BPA had used the least cost alternative. Peseau, DSI, E-DS-10, 33. The DSI object to splitting the cost in half since this results in the DSI's receiving less than the true value of the reserves. Opening Brief, DSI, B-DS-01, 51. The DSI's also assert that failure to pay full value for the right to restrict the DSI load is inconsistent with BPA's policy of paying full value for other generating resources, billing credits, and conservation programs. Reply Briefs, DSI, R-DS-01, 17.

It is not true that BPA will pay the "full value" of its otherwise least-cost alternatives when acquiring generating resources, billing credits, and conservation programs. In acquiring generating resources, BPA would normally expect to pay based on the cost of those resources, not the cost of other alternatives. Similarly, in implementing conservation programs, BPA pays based on the cost of the program, not the cost of alternative generation, and in many cases does not pay the full cost. These costs are shared with the individual conserver and, for utilities with non-BPA loads, with the conserving utilities through the conservation contract charge. In granting billing credits, the Regional Act states, "[f]or resources other than conservation, the customer shall be credited for the net costs actually incurred by such customer . . ." Section 6(h)(4). Thus, it is only for billing credits for conservation acts independently undertaken that BPA pays based upon alternative costs.

In the initial proposal, BPA used a share-the-savings approach to determine the credit to the DSI's for BPA's right to restrict the DSI load for reserve purposes. The right to restrict the DSI load results in benefits to BPA and its customers. Section 7(c)(3) of the Regional Act requires the Administrator to adjust the DSI's rates "to take into account" the value of reserves. The statute and principles of condemnation law do not require the Administrator to credit the DSI's with the "full value." The Senate Committee Report, Appendix B, 64, further supports BPA's position that a share-the-savings approach is lawful, stating:

> The amount of Reserve Adjustment credited to the DSI's under this study of the program is equal to one-half of the total value of the reserves. Thus, approximately one-half of the savings to the region, in not building standby generating reserves, was credited to the DSI's for providing these reserves, and the remaining one-half was shared among the region's firm loads including 50 percent of the DSI load. The crediting of 50 percent of the value of the reserve to the DSI's does not set a precedent for future rate cases.

While Appendix B states that the 50 percent share-the-savings approach is not mandated by section 7(c)(3) of the Regional Act, the legislative history negates the argument that the Regional Act requires BPA to base the credit on 100 percent of the value.

The DSI's agree with BPA that Appendix B does not direct BPA to follow a share-the-savings approach in subsequent rate filings. However, they contend that 7(c)(3) of the Regional Act also does not preclude BPA from granting full credit to the DSI's for the value of the reserves they provide. Reply Brief, DSI, R-DS-01, 19.

Both the PPC and PP&L disagree with the DSI's claim that the DSI's are entitled to full value of the reserves provided by BPA's ability to restrict the DSI load. Opening Brief, PPC, B-PP-01, 48-50; Reply Brief, PPC, R-PP-01, 23-27; Reply Brief, PP&L, R-PL-01, 10-12. The PPC notes that although the legislative history does not restrain the Administrator's discretion in granting the DSI's a credit for the reserves required, a sharing of benefits between the DSI's and the rest of the region was anticipated and endorsed. Opening Brief, PPC, B-PP-01, 52; Reply Brief, PPC, R-PP-01, 27.

In their opening brief, PP&L advanced the proposal that calculation of the credit to the DSI for BPA's right to restrict their load should not include the cost of an outage to the DSI's. Rather, they suggest that credit should equal one-half the calculated value of reserves. PP&L suggests that the share-the-savings approach used by BPA results in the DSI's receiving more than one-half of the value of the reserves. Opening Brief, PP&L, B-PL-01, 12; Reply Brief, PP&L, R-PL-01, 9.

Decision

BPA used a share-the-savings approach to determine the value of reserves credit. This is the approach used in the last rate case and shares risk and benefits associated with providing reserves through restriction rights between the interruptible DSI load and the other firm power customers. Including the cost of an interruption to the DSI's in the calculation recognizes that providing reserves through restriction of the DSI load is beneficial to the region, yet also imposes costs on the DSI's when restricted.

Issue #2

How should the revenue deficiency resulting from the value of reserves credit be allocated?

Summary of Positions

In the initial proposal, the DSI's credit for the reserves provided by BPA's ability to restrict their load created a revenue deficiency that was allocated to all firm customers. BPA, E-BPA-7, 20.

The DSI's argued that the resulting credit should be allocated to all loads except those served by exchange resources. They further argued that if exchange resources continue to pay for the reserves provided by the DSI restriction rights, then the DSI load providing those reserves should not be allocated the cost of the reserves. This would be accomplished by allocating the plant delay reserve cost to the third and fourth quartiles, the forced outage reserve cost to the fourth quartile and the stability reserve cost would not be allocated to the DSI load. Peseau, DSI, E-DS-10, 33-38.

Evaluation of Positions

In the initial proposal BPA allocated the revenue deficiency resulting from the value of reserves credit to all firm load. BPA, E-BPA-7, 20. The Regional Act specifically directs BPA to adjust rates to provide for a DSI reserve credit. Therefore, the reserve credit allocation is removed from the resource pool analysis and allocated to all firm loads. This is consistent with the method used in Appendix B to Senate Report 96-272 (96th Congress, 1979), and in BPA's 1981 and 1982 rate cases. Metcalf, BPA, E-BPA-32, 10.

BPA argued that allocation of the cost of the reserves to the loads providing the reserves is appropriate because those loads are included in the determination of the amount of combustion-turbine capacity needed. Metcalf, BPA, E-BPA-32, 10. APAC supports BPA's allocation of the cost of resources to all firm load as this maintains consistency with previous rate cases. Reply Brief, APAC, R-PA-01, 29-30. The DSI's reply that the level of reserves is now based on test year resources. Peseau, DSI, E-DS-10, 36. However, the DSI's offer no explanation for why that is relevant. The level of reserves is based on resources, and BPA plans resources to serve the lower three quartiles.

The DSI's argued that exchange resources should not be allocated the revenue deficiency resulting from the reserve credit because allocating the reserve credit in this manner results in double counting. They claim the costs of exchanging utilities' reserves are included in their average system costs. Wilson, DSI, E-DS-11, 6. Loads paying the cost of the exchange are covering the reserve cost of the exchanging utilities. According to the DSI's allocating the revenue deficiency from the reserve credit to those loads that pay exchange costs results in those customers paying for the reserve costs of exchange resources and the reserve costs of Federal resources. Peseau, DSI, E-DS-10, 35.

The NWU's reject all double-counting arguments. They contend that it is irrelevant what costs are included in the exchange. It is appropriate for BPA to add on a share of its costs to the exchange costs just as it does to FBS and new resources costs. McCullough, NWU, E-NW-5, 3. However, the NWU's argument overlooks the basic principle of cost causation. The point is not so much that reserve costs are included in the cost of the exchange, but that the exchange comes complete with reserves (and transmission, etc.). BPA does not have to provide reserves (or transmission, etc.) for this resource as it does for FBS and new resources. Contrast this case with those areas where the double counting arguments have been rejected. In the case of cash lag and administrative costs, the exchange does impose these costs on BPA.

Decision

The revenue deficiency resulting from the value of reserves credit was allocated to all firm load served by FBS and new resources. The level of reserves required in the test year was based on a percentage of Federal resources on line during OY 1985. Exchange resources were not included in this determination. Thus, the reserves are protecting the resources in the FBS and new resource pools. Since these resource pools are receiving the protection provided by the reserves, they are allocated the cost of the reserves. The question of whether the reserve credit should be allocated to the quartiles providing the credit is moot for this rate proposal, because those quartiles are all served by exchange resources.

4. Surplus Firm Power Revenue Deficiency

Only a portion of BPA's surplus firm power is forecast to be sold at the SP-83 rate. The balance of the surplus will be sold at the lower NF-83 rate, resulting in a revenue underrecovery.

Issue #1

How should BPA allocate the revenue deficiency from the failure to sell surplus firm power at fully allocated cost?

Summary of Positions

BPA proposed to determine the revenue deficiency by subtracting from the allocated costs the revenues derived from the sale of surplus firm power on the open market. Next, the deficiency is prorated among the cost components of surplus firm power. These components are exchange resources, new resources, and an adder (transmission and overhead). Revenue deficiencies attributable to the exchange resource cost component are allocated to the Industrial Firm Power class. New resource and adder revenue deficiencies are allocated to all firm sales. BPA, E-BPA-7, 22-23; Melton, BPA, E-BPA-10, 27; Metcalf, BPA, E-BPA-32, 11-12.

The DSI's contend that BPA should "add the cost of (surplus) resources to the nonfirm rate since unsold surplus eventually becomes nonfirm power," or allocate the costs to all firm loads which BPA forecasts it will serve. Wilcox, DSI, E-DS-01, 33; Carter, DSI, E-DS-09, 13. If neither measure is adopted, the cost of the unsold surplus should be allocated to all power customers. Wilcox, DSI, E-DS-01, 34. Another DSI proposal is to allocate the costs exclusively to users of the FBS. Drazen, DSI, E-DS-07, 15.

The DSI's opening brief and reply brief stress their belief that BPA must allocate the cost of unsold surplus among all customers. These costs are to be allocated pursuant to section 7(g) of the Regional Act, "except insofar as the preference customers are protected by Section 8(1) of the GCPs." BPA must allocate some costs to 7(b) purchasers, even if this requires a two-part 7(b) rate. Opening Brief, DSI, B-DS-01, 110; Reply Brief, DSI, R-DS-01, 11, 30-31, 53-54.

The PPC states that "the 8(1) settlement forbids charging unsold surplus exchange costs to preference customers' general requirements rates" and, consistent with BPA's resource stacking approach, the unsold surplus must be allocated to the DSI's. Opening Brief, PPC, B-PP-01, 8-10; Reply Brief, PPC, R-PP-01, 41.

The PPC believes that BPA should compare actual surplus firm sales to forecast sales for the period ending May 1984. Revenue deficiency or overrecovery should be allocated to "the rate classes bearing responsibility" for the variance from forecast. Wolverton & O'Meara, PPC, E-PP-02R, 28-29; Opening Brief, PPC, B-PP-01, 21.

Evaluation of Positions

BPA forecasts that sales of surplus firm power sold at the NF-83 rate will be made at both the Standard and Spill rates, in the same proportion as other NF-83 sales. BPA, E-BPA-7, 21-22; Metcalf, BPA, E-BPA-32, 11-12. The resulting revenue deficiency (allocated cost less nonfirm revenue) would then be prorated according to the three cost components of Surplus Firm Power. BPA, E-BPA-7, 22-23; Metcalf, BPA, E-BPA-32, 12. However, the guarantee options of the final NF-83 rate need to be incorporated into this methodology. It is necessary to compare the availability of unmarketable surplus firm, on a monthly basis, with forecast guaranteed Standard and Spill sales. Then, to the extent possible, the guarantee sales should be identified as the sale of marketable surplus firm in order to determine the resultant revenue underrecovery.

It is also necessary to model the use of the surplus firm to serve the DSI first quartile. See, BPA, Evaluation of the Record, 192-193. Since the first quartile is priced at the generation portion of the average nonfirm rate, it is appropriate to assume recovery of that amount of revenue from the surplus firm used to serve the first quartile.

The DSI's assertion that unsold surplus "becomes nonfirm power" is correct only from a marketing perspective. Wilcox, DSI, E-DS-01, 33; Carter, DSI, E-DS-09, 13. The reason the power is sold at the NF rates is that it cannot be marketed at the higher SP rate. Marketing the power at a lower rate does not, however, alter the composition of the exchange and new resource pools that, for ratemaking purposes, contribute to the availability of the power. Since the resource pools are not affected by the rate at which the surplus power is marketed, it would be improper to associate any underrecovery of allocated cost to other than the new resource and exchange resource pools. Moreover, the DSI's have no demonstration of the amount of nonfirm energy BPA would still be able to market if the revenue deficiency were recovered through nonfirm rates.

The DSI's argue that allocation to nonsurplus rates of the unrecoverable costs attributable to unsaleable surplus firm power is, in effect, an allowance for a contingency. Opening Brief, DSI, B-DS-01, 100. Section 7(a)(1) of the Regional Act requires the Administrator to establish rates "to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power . . ." (Emphasis added.) Section 7(a)(2) repeats this mandate by authorizing FERC to approve the filed rates only if, inter alia, they "are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs . . ." (Emphasis added.) Section 7(c)(1)(A) explicitly directs the Administrator to include in the DSI rates those net costs of the residential exchange which "are not recovered through rates applicable to other customers . . ." The cited paragraphs and subparagraphs obviously require the Administrator to establish rates that reasonably assure recovery of projected costs. The directive to use sound business principles provides the Administrator with substantial discretion as to how such costs are to be recovered. It also directs him to make his decisions based on the best information available. It would not be in accordance with sound business principles for the Administrator to ignore his projected inability (based on detailed staff studies) to sell some of the surplus firm power at the SP rate by setting his rates on the principle that such sales should be made. Such a course would, in effect, be a choice to underrecover costs, contrary to sound business principles. Nothing in the Regional Act requires the Administrator to ignore reality. To project that some surplus firm power will not be sold at the SP rate is not to create a contingency, as asserted by the DSI's, but rather a well-considered forecast of what will happen.

Another indication that the Administrator is authorized to establish his rates on the premise that a certain amount of surplus firm power will not be sold at the SP rate is found in section 7(g) of the Regional Act. That section directs the Administrator to "equitably allocate to power rates . . . all costs and benefits not otherwise allocated under this section, including . . . the sale of or inability to sell excess electric power." No clearer evidence could be found of Congressional intent that BPA not ignore its forecasts. Indeed, it is admitted in the DSI's opening brief that "section 7(g) of the Regional Power Act controls the allocation of 'unsold surplus' costs, to the extent not otherwise restricted." Opening Brief, DSI, B-DS-01, 107.

The DSI's argue that BPA cannot lawfully allocate all "unsold surplus costs" to them. BPA proposes to allocate to the DSI's the revenue deficiency associated with unsold surplus firm power that is attributable to surplus exchange resources. The DSI's argue that such an allocation is not equitable under section 7(g) of the Regional Act. Opening Brief, DSI, B-DS-01, 105; Reply Brief, DSI, R-DS-01, 54.

Clearly, section 7(c)(1)(A) directs the Administrator to recover, from the DSI's, the net costs of the exchange resource to the extent that such costs are projected not to be recovered from other customers. That section directs the Administrator to establish DSI rates for the period prior to July 1, 1985, "to recover . . . 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." The legislative history of section 7(c) states that "the direct-service industrial customers of BPA are required to pay the costs of the exchange during its initial years." House Interior Committee Report, H. Rpt. No. 96-976, Part II, 35 ("Interior Report") (emphasis added). See also Senate Report, Rpt. No. 96-272, 15 ("Senate Report"); House Commerce Committee Report, H. Rpt. No. 96-976, Part I, 29 ("Commerce Report"). The reference to "rates applicable to other customers" is a reference to the use of the exchange resources to serve non-DSI loads, such as 7(b) loads pursuant to section 7(b)(1). See Senate Report, 59.

With respect to the revenue deficiency associated with the remaining costs of the unsold surplus firm power that corresponds to surplus exchange resources, the Administrator must allocate those deficiencies under section 7(g) of the Act and pursuant to the settlement reached in PPC v. Johnson on the allocation of exchange costs ("8(l) settlement"). Section 7(g) is a general grant of authority to include in power rates the costs and benefits that are not otherwise specifically addressed elsewhere in the Act. As the DSI's correctly argue, the allocation of these costs must be equitable. The 8(l) settlement prohibits BPA from allocating to preference customers (for their general requirements) any of the revenue deficiencies associated with unsold surplus firm power which is attributable to surplus exchange resources and allocated under section 7(g). The terms of this settlement were not challenged by the DSI's. Equity under section 7(g), therefore, must be measured within the context of the terms of that settlement. Thus, in addition to the DSI's, the remaining customer groups to which this revenue deficiency might be allocated are 7(f) customers and customers purchasing 7(b) power pursuant to the residential exchange. The DSI's have claimed that costs of unsold surplus firm power, except the net cost of the residential exchange resource, must be allocated to both of these groups pursuant to section 7(g). Opening Brief, DSI, B-DS-01, 110; Reply Brief, DSI, R-DS-01, 53. However, section 7(g) provides the Administrator with the authority and flexibility to allocate such costs to power rates in a manner he determines to be equitable and appropriate. It does not require him to allocate such costs to all customers, or to all customers equally. Senate Report, 32. In addition, a decision to not allocate any of these costs to customers purchasing 7(b) power under the exchange maintains wholesale rate parity between BPA's publicaly owned and investor-owned utility customers, as regards the residential and small farm retail customers served by these utilities.

The DSI's have not shown why the Administrator must allocate these costs to exchange purchases. Their references to section 7(g) as mandating such an allocation are incorrect. In the face of what is at least a strong Congressional expectation that exchanging customers pay the same rate for 7(b) power as preference customers pay for their general requirements, BPA should not restructure its proposed allocation of the revenue deficiency associated with unsold surplus exchange resource costs. Given that approach, it makes little sense to allocate costs to the relatively miniscule amount of power sold pursant to section 7(f).

The PPC proposes a "mid-course" correction. This alternative would result in BPA's being able to recover costs from overforecasting potential surplus power sales. In turn, if BPA had underforecast such sales, the alternative would result in a lowering of the rate to classes bearing responsibility for the surplus firm power revenue deficiency. If BPA were to adopt this alternative, it would reduce the risk associated with those sales. Wolverton & O'Meara, PPC, E-PP-02R, 28-29; Opening Brief, PPC, B-PP-01, 21.

A "mid-course correction" is a reasonable idea although the PPC did not make a specific recommendation as to how the actual deficiency would be calculated to compare with the forecasted deficiency. In particular, no treatment was suggested for changes in surplus firm power sales caused by changes in other firm loads or firm resources. It is virtually impossible to sort out the reasons why actual revenues deviate from forecast, especially given the complicated interactions between BPA's firm sales, surplus firm sales, and nonfirm sales. Revitch, BPA, E-BPA-28, 4-5.

Decision

The determination of the SP revenue deficiency has been modified to associate guaranteed NF-83 sales with the surplus sold in the nonfirm market. It has also been modified to reflect service to the DSI first quartile.

The costs of the SP revenue deficiency have been allocated in the manner described in the initial proposal. The various DSI proposals for eliminating the underrecovery are inconsistent with the realities of the situation. Some recommended allocations are legally problematic. The PPC proposal for a mid-course correction, while attractive in many ways, has too many practical problems associated with it.

Issue #2

Should revenues from surplus firm power sold as nonfirm energy be considered excess revenues and be credited in the same manner as other excess revenues?

Summary of Positions

For the initial proposal, BPA forecast that some surplus firm power will go unsold at the cost-based SP-83 rate and will, instead, be sold at the lower NF-83 rate. The resulting revenue deficiency (allocated surplus firm cost less NF-83 revenues) will be prorated among the cost components of surplus firm power. BPA, E-BPA-7, 22-23.

The WWPUD's contend that the revenues from sales of surplus firm resources sold at the NF-83 rate "should be treated in the same fashion as all other revenues from nonfirm sales. That is, they should be considered excess revenues and credited in the same manner as all other excess revenues." Hutchison, et al., WWPUD, E-WW-01, 50; Opening Brief, WWPUD, B-WW-01, 73-74.

Evaluation of Positions

Surplus firm power is composed primarily of exchange resources. BPA, E-BPA-7, 23. The WWPUD's proposal, however, would credit the FBS for surplus firm power sold at NF-83 rates despite the fact that FBS resources do not contribute (for ratemaking purposes) to surplus resources. Hutchison, et al., WWPUD, E-WW-01; Opening Brief, WWPUD, B-WW-01, 73-74. This method is inconsistent with the resource stack approach used in cost allocation. The WWPUD's give no rationale for why the sale of exchange resources, whether at the SP or the NF rate, should be credited to the FBS.

Decision

Revenue from surplus firm power sold as nonfirm energy has been treated as a reduction in the surplus firm power revenue deficiency. The WWPUD's proposed methodology is inconsistent with BPA's resource stack approach used in cost allocation.

5. Equalization of Demand

BPA included uniform (equalized) demand charges for sales to PF, IP, CF, NR, and SP customers in the initial proposal. The issues associated with equalization of demand are discussed under the CF-83 rate and the NR-83 rate.

6. Hanna

Hanna Nickel Smelting Company (Hanna) receives special rate consideration from BPA pursuant to section 7(d)(2) of the Regional Act. The resulting revenue deficiency is allocated to all other customers. There were no issues raised in the rate hearing related to BPA's allocation of the revenue deficiency resulting from the special rate granted to Hanna.

C. Charges and Adjustments Applying to More than One Rate Schedule

Issues about charges and adjustments that apply to more than one rate schedule are discussed in this section. BPA's unauthorized increase charge, computed requirements billing factors, adjustment clauses, and shoulder period demand charges are all discussed below.

1. Unauthorized Increase Charge

An unauthorized increase is an unscheduled or unrequested firm power purchase in excess of a purchaser's Operating Demand or Contract Demand. BPA's firm power rate schedules include the unauthorized increase charge.

Issue #1

Is an unauthorized increase charge appropriate or cost-based during periods of surplus firm power?

Summary of Positions

BPA believes that it is appropriate to include a charge for unauthorized increase in the wholesale power rates, despite the availability of surplus firm power. BPA, E-BPA-7, 27-28. The proposed rate is cost-based since it represents the variable costs of operating a combustion turbine. BPA, E-BPA-7, 27-28.

The PGP claims that an unauthorized increase charge is inappropriate during a period of power surplus, and that BPA's proposed charge is not cost-based. Garman, et al., PGP, E-PG-01, 72; Opening Brief, PGP, B-PG-01, 30.

Evaluation of Positions

PGP makes three fundamental arguments with respect to the unauthorized increase charge. First, they assert that the charge is unreasonable during a period of power surplus. Second, in their view, the amount of the charge (if a charge should be applied) should be no greater than the LRIC of energy.

Finally, the PGP claims that the charge causes them operational problems. Garman, et al., PGP, E-PG-01, 72-73; Opening Brief, PGP, B-PG-01, 30.

PGP argues that the charge should not be applied during periods of capacity and energy surpluses. Garman, et al., PGP, E-PG-01, 72. Given the size of BPA's surplus, it may be that load overruns by the generating publics will not impose significant additional costs on BPA. However, the PGP position completely misses the point. The unauthorized increase charge is not an average-cost based charge for a service offered by BPA. Instead, it is a penalty for a violation of the service conditions agreed to by both BPA and the customer. As such, the charge is based on the highest cost resource which BPA might have to purchase to protect its firm loads in such a situation. It is entirely appropriate for the rate to apply to all load/resource periods since the purpose of the charge is to discourage customers from scheduling more power (on an hourly or daily basis) than was originally requested on a monthly basis under the contracts.

PGP also argues that the charge should be no greater than the LRIC of energy. Garman, et al., PGP, E-PG-01, 72; Opening Brief, PGP, B-PG-01, 30. However, the LRIC reflects BPA's long run costs, not necessarily the costs which BPA would incur if it had to make short-term power purchases to meet a given load. Consequently, the charge is based on the cost which BPA might have to pay in order to acquire a resource to meet the unauthorized load. BPA, E-BPA-7, 27-28. BPA has determined that the highest cost that BPA may incur is 83 mills per kilowatthour, which represents the running costs of a single-cycle cumbustion turbine. BPA, E-BPA-7, 89.

Furthermore, PGP claims that the unauthorized increase charge forces customers to understate their power requirements from BPA preventing them from taking full advantage of their contracts. Garman, et al., PGP, E-PG-01, 73. They also state that the penalty rate discourages utilities from developing and using generation to meet part of their load. Garman, et al., PGP, E-PG-01, 74. However, the PGP does not demonstrate how the unauthorized increase charge serves as an inducement to understate loads, nor how such an understatement of loads on BPA discourages the development of their own generation. (It should be noted that the PGP has criticized both the availability charge because it encourages development of utility-owned resources and the unauthorized increase charge because it discourages such development.) Also, the utilities' flexibility accounts tend to prevent the surcharge on energy from applying to load overruns, provided the accounts can still be balanced by the end of the operating year. The Relief from Overrun Exhibit of the power sales contract also limits the applicability of the Unauthorized Increase.

Decision

The charge for unauthorized increase has been developed in the manner described in the initial proposal. It is proper to apply the charge during a period of surplus power since the rate is a penalty charge, rather than an average-cost based rate.

2. Computed Requirements Billing Factors

BPA has two types of requirements customers, metered requirements and computed requirements. Most metered requirements customers purchase all their power requirements from BPA; the rest are required to operate their resources in a contractually specified manner. All computed requirements customers, on the other hand, have their own generation and have more contractual flexibility in the use of their resources. In the initial proposal, BPA modified the computed requirements billing factors in the PF and NR rates to reflect the fact that BPA must stand "ready to serve" computed requirements customers under critical water conditions despite the fact that they may elect to displace their purchases from BPA.

There are many issues related to the computed requirements customers' billing factors question. The first has to do with the causes of BPA's revenue recovery problems; i.e., to what extent have the computed requirements customers contributed to BPA's revenue shortfall? Second, what are the operational and economic effects of BPA's proposal? Third, is the proposal fair to all concerned? Fourth, is the proposed availability charge, as it is called by the parties, legal? Fifth, how should BPA compute the availability charge? Finally, are there other, more appropriate ways of solving BPA's revenue stability problem? Each of these issues is discussed separately, but no decision is presented for the separate discussions. The BPA decision is given in subsection g, at the end of the discussion of all the issues affecting the decision. All the relevant considerations from the issues discussed in sections a-f are brought together in the BPA decision.

a. Causes of BPA's Revenue Recovery Problem

Issue #1

How much has the computed requirements customers' ability to displace firm purchases from BPA contributed to BPA's revenue underrecoveries?

Summary of Positions

In the initial proposal, BPA identified the computed requirements customers as a major source of revenue instability, and proposed measures to mitigate future revenue shortfalls attributable to those customers. BPA included a modified take-or-pay charge for computed requirements purchasers because they have been significantly underrunning their projected loads. Metcalf, BPA, E-BPA-32, 18-19. In rebuttal testimony, BPA presented data which demonstrated that the total revenue underrun by computed requirements customers was, at times, greater than that of metered requirements purchasers even though the computed requirements load is only approximately one-third the size of the metered requirements load. Metcalf, BPA, E-BPA-46R, 4-5.

According to the PGP, however, a comparison of forecast and actual revenues "shows that economic displacement of BPA firm purchases accounts for a minimal portion of total revenue underrecovery." Garman, et al., PGP, E-PG-06R, 10. The PGP attributes BPA's revenue problems to economic conditions, mild weather, and water conditions. Garman, et al., PGP, E-PG-01, 16.

APAC maintains that BPA's underrecovery comes from many sources, not just the PF and IP classes. Consequently, BPA's emphasis on an "energy ratchet" or "take-or-pay" is misplaced if BPA's concern is related to revenue recovery. Cook, APAC, E-PA-02, 46-47. APAC notes that only 9.73 percent of the PF revenue shortfall is related to generating utilities. Cook, APAC, E-PA-2, 46.

PP&L contends that the revenue shortfall from the PF class is the result of the decline in all billing determinants for the PF rate class. Sirvaitis, PP&L, E-PL-05R, 5.

The WWPUD's agreed with BPA's analysis of the causes of the revenue shortfall and stated that BPA's proposal represents "an appropriate step to address a specific revenue recovery problem." Hutchison, et al., WWPUD, E-WW-01, 39.

Evaluation of Positions

BPA supported its position that computed requirements customers contribute significantly to BPA's revenue recovery problems by noting that "the forecasted revenue from computed requirements customers in FY 1983 is barely more than one-third of the forecasted revenues from metered requirements customers ($133,103,000 vs. $360,591,000, Table 4). Yet, the priority firm power revenue shortfall attributable to computed requirements customers is $1.44 million greater than the priority firm power revenue shortfall attributable to metered requirements customers ($47,669,000 - $46,228,000)." Metcalf, BPA, E-BPA-46R, 3. The computed requirements loads are, by nature, more volatile than the loads of metered requirements customers because of their additional operational flexibility and since a 10 percent reduction in load of a customer purchasing half of its power from BPA would result in 20 percent reduction in purchases from BPA. Metcalf, E-BPA-46R, 4-5.

In response to PGP's prefiled testimony, BPA presented data in rebuttal testimony showing that 85 percent of the energy load reduction in FY 1982 for planned and actual computed requirements customers was the result of displacement, while only 15 percent was caused by factors such as the depressed economy and mild weather. Metcalf, BPA, E-BPA-46R, 3. In computing the percentage displacement, BPA assumed that all reductions in load for planned computed requirements customers were displacements, since the forecast for planned computed requirements customers is deemed to be the actual load. Metcalf, BPA, E-BPA-46R, 4; Metcalf, BPA, E-BPA-32, 17. Additional information presented in BPA's prefiled testimony showed that scheduling customers bought only 67.7 percent of their computed energy load during FY 1982 and as little as 14.6 percent of the power they were entitled to take during February 1983. Metcalf, BPA, E-BPA-32, 18.

The PGP disagrees with BPA's assertion that they are largely responsible for the shortfall from the PF class. Garman, et al., PGP, E-PG-01, 16. To prove their point they cite an analysis that shows that public generators contributed only $12.3 million (3.8 percent) to the $327 million shortfall. Garman, et al., PGP, E-PG-01, 17. In rebuttal testimony, the PGP claimed that only 5.4 percent of the underrecovery is associated with displacement (measured by comparing the Computed Average Energy Requirement and the average Measured Energy). Their data shows that for the first five months of FY 1983, PGP members accounted for less than one-third of the total underrecovery from the PF class. Garman, et al., PGP, E-PG-06R, 11. The PGP also noted that the metered requirements customers are subject to load reductions due to weather and economic conditions as well. Garman, et al., PGP, E-PG-06R, 11-12. The PGP asserts that the "two major causes are (1) variance in sale to all customer classes due to overly optimistic load forecasts and (2) over-reliance on the energy component of the BPA rates to recover BPA's revenue requirement." Opening Brief, PGP, B-PG-01, 13.

BPA noted that most displacement by computed requirements purchasers occurs when BPA is selling at the Spill rate. Metcalf, BPA, E-BPA-32, 19. At that time, it is unlikely that the additional revenue gained from selling displaced energy in the nonfirm market (assuming the energy can be sold at all) would equal the allocated costs. Metcalf, BPA, E-BPA-32, 27; Metcalf, BPA, E-BPA-46R, 5. In contrast, metered requirements customers' load underruns tend to be unrelated to water conditions, so more of the displaced energy can be sold at the Standard rate. Metcalf, BPA, E-BPA-46R, 5. Consequently, BPA proposed new billing factors to mitigate the revenue loss from computed requirements customers.

Although the data presented by the PGP and BPA in their respective rebuttal cases seem contradictory, the PGP's witness noted in cross-examination that he agreed with BPA's data. Garman, PGP, TR 8292. A major reason that BPA's and PGP's data differ is that PGP's data do not include any information for the spring months. During those months considerable displacement takes place, so the PGP data does not accurately reflect the extent of the displacement problem. Garman, PGP, TR 8291-8292.

PP&L is correct that the billing determinants for the PF class as a whole have declined. Sirvaitis, PP&L, E-PL-05R, 5. However, the billing determinants for the computed requirements customers have, as demonstrated by BPA, declined proportionately more than the billing determinants for metered requirements customers. The WWPUD's agreed with BPA's assessment of the problem. Hutchison, et al., WWPUD, E-WW-01, 39.

b. Effects of BPA's Proposal

Issue #1

Would BPA's proposed billing factors have adverse operational or economic effects on BPA's computed requirements customers?

Summary of Positions

In the initial proposal, BPA did not directly address the question of how BPA's rate structure would influence the operation of computed requirements customers' systems. In rebuttal, BPA noted that computed requirements customers have operational flexibility with respect to their systems. Metcalf, BPA, E-BPA-32, 15-18.

The PGP stated that the availability charge sends three inappropriate signals to customers. First, the charge encourages inefficient operation of regional resources since computed requirements customers would lose their flexibility to use BPA firm power in an optimum manner. Garman, et al., PGP, E-PG-01, 19; Garman, et al., PGP, E-PG-06R, 13-14; Opening Brief, PGP, B-PG-01, 14. Second, the charge will result in utilities discouraging energy conservation and, finally, computed requirements customers will ultimately be likely to develop or acquire non-BPA firm resources to minimize the adverse economic effects of the energy billing determinants. Garman, et al., PGP, E-PG-01, 19; Garman, et al., PGP, E-PG-06R, 13-14. The PGP contends that such an effect is "without foundation" during a period of surplus. Garman, et al., PGP, E-PG-01, 19.

APAC concurs with PGP's position. They also note that BPA did not take into account the elasticity effect of its proposal. Opening Brief, APAC, B-PA-01, 89-92.

Evaluation of Positions

In rebuttal testimony, BPA observed that actual computed requirements purchasers would not be penalized under the proposal for reductions in retail load since both the Computed Energy Maximum and the Measured Energy are reduced when load is reduced. Planned and contracted computed requirements customers are, however, vulnerable to short-term load reductions, but they chose the increased operational flexibility that goes along with their increased vulnerability when they selected their respective computed requirements options. Metcalf, BPA, E-BPA-46R, 4.

With respect to system operation, the PGP contends that the availability charge will make it difficult to operate the utilities' systems given the unauthorized increase charge on the upper end and the availability charge on the lower end. Garman, et al., PGP, E-PG-01, 19. "Because the customer cannot foresee the effects of weather, unplanned industrial shutdowns, or other occurrences beyond its control in the month prior to delivery, there is no method by which the customer can accurately estimate his load in order to take full advantage of his contract entitlements." Garman, et al., PGP, E-PG-01, 73. The PGP continues to assert that, in order to avoid the availability charge computed requirements customers must precisely forecast their load. Reply Brief, PGP, R-PG-01, 4. Yet that is simply not the case. All the public generators except Tacoma are actual computed requirements customers. As such, their Computed Energy Maximum, upon which the availability charge is based, is equal to their actual load less their assure resource capability. Metcalf, BPA, E-BPA-37, 16-17. The PGP's own witnesses agreed that the availability charge in no way penalized an actual computed requirements customer for deviations from load forecasts. Garman, PGP, TR 8295. This problem is also alleviated by the flexibility accounts and the Relief from Overrun Exhibit to the power sales contract. Power Sales Contract, section 17(d), Exhibit F.

Although the PGP and APAC asserted that the availability charge encourages inefficient operation of resources, no evidence or explanation was given. In fact, during cross-examination, the PGP admitted that the proposed charge would have no effect on generating utilities if they were to market their own nonfirm, and they agreed that there is nothing inefficient about the generating utilities marketing their own nonfirm. Garman, PGP, TR 8292-8294.

The PGP also asserts that imposition of any sort of availability charge is inconsistent with BPA's conservation goals. Garman, et al., PGP, E-PG-01, 18-19. In particular, PGP notes that factors that increase the deviation from the level forecast for planned computed requirements purchasers will increase the customer's exposure to BPA's charge. Garman, et al., PGP, E-PG-06R, 14.

The PGP is correct that unexpected conservation on the part of consumers or a failure to conserve may affect planned computed requirements customers. However, the problems may not be as significant as they might initially appear since load underruns resulting from conservation can be reflected in the utility's load forecast. As to whether conservation programs would increase load forecasting unpredictability, the PGP made that assertion, but presented no evidence. It could be that such programs would improve predictability of loads by decreasing the proportion of the load that is weather-sensitive. In addition, as BPA pointed out in its testimony, planned computed requirements customers chose to be "planned" because they desired increased operational flexibility. In return, they accepted a certain degree of risk. Metcalf, BPA, E-BPA-46R, 4. No evidence has been presented which demonstrates that planned computed requirements customers will in fact decrease their conservation activities as a result of BPA's adopting the proposed billing factors.

Both BPA and the PGP agree that actual computed requirements customers would not be penalized under BPA's proposed energy billing factors for "any reduction in their load due to conservation or any other factor such as weather or the economy." Garman, PGP, TR 8295. Thus, there should be no effect on conservation undertaken by actual computed requirements customers if BPA were to adopt the proposed billing factors.

With regard to the argument that the "availablility charge" will cause computed requirements customers to build their own resources, the PGP seems to have taken contradictory positions. They state that the charge would induce them to build more resources to minimize the adverse impact of charge. Garman, et al., PGP, E-PG-06R, 14. Yet, in oral argument their counsel implied that the proposed billing factors lowered the value of the utilities' own generation. Waldren, PGP, TR 8995-8996. Also, they admit that a utility that did not buy any power from BPA would lose the flexibility to displace half the PF energy charge. Garman, PGP, TR 8297-8298. In their discussion about the effects of the charge on conservation, they forget their own assertion that alternative resources would be made more attractive if BPA were to impose the proposed charge.

The PGP also argues that the "availability charge" is an ad-hoc solution to a "short-term" problem. They assert that the problem only arises because of the surplus. During a deficit BPA would want to encourage displacement by generating utilities. Garman, et al., PGP, E-PG-01, 20; Opening Brief, PGP, B-PG-01, 15.

In response to PGP's assertion that BPA's proposal is an ad-hoc solution to a problem that will disappear in time of deficit, BPA noted that even in deficit periods, computed requirements customers would tend to displace their purchases from BPA only at times when the displacement would be disadvantageous to BPA. Metcalf, BPA, TR 5776. That is, computed requirements purchasers would displace when the region was having such a good water year that the market price for nonfirm was below the PF energy charge.

c. Equity Issues

Issue #1

Is it appropriate for BPA's billing factors to reflect the contractually permitted operational flexibility enjoyed by computed requirements purchasers?

Summary of Positions

In prefiled testimony BPA noted that "recently, computed requirements customers have been displacing firm purchases from BPA with their own nonfirm energy and nonfirm energy purchases from other utilities." Metcalf, BPA, E-BPA-32, 15. Since this same flexibility is not enjoyed by metered requirements customers, BPA did not propose a similar billing provision for metered requirements customers. Metcalf, BPA, E-BPA-32, 26.

The WWPUD's believe that BPA's proposed billing factors for computed requirements customers are appropriate. Hutchison, et al., WWPUD, E-WW-01, 39-40; Opening Brief, WWPUD, B-WW-01, 64.

The ICP agreed that computed requirements purchasers may, in most cases, have more flexibility than do metered requirements customers to use nonfirm for displacement. Lauckhart, ICP, TR 7557. However, the ICP asserts that in return for this increased flexibility, a computed requirements customer assumes certain risks which, by implication, should entitle it to corresponding benefits. Lauckhart, ICP, TR 7562. The ICP's position was also endorsed by APAC. Cook, APAC, TR 7510-7511.

PGP argues that the proposed billing factors will "unilaterally" take away the flexibility that the generating utilities are entitled to by law and by contract. Opening Brief, PGP, B-PG-01, 17.

Evaluation of Positions

The WWPUD's observed that although metered requirements purchasers react to weather and price (see section 3.b.(1), issue #1), they do not have the same contractual flexibility concerning supply choices as do the computed requirements customers. For this reason the WWPUD's believe that BPA's proposed billing factors for computed requirements customers are appropriate. Hutchison, et al., WWPUD, E-WW-01, 39-40; Opening Brief, WWPUD, B-WW-01, 64.

Although APAC agreed with BPA that computed requirements purchasers have greater operational flexibility than do metered requirements purchasers, Cook, APAC, TR 7508-7509, APAC agreed with the PGP that under critical water conditions BPA does not have the obligation to supply any firm energy required to make up the deficits which the utilities have assumed under their contract. Cook, APAC, TR 7511-7512. However, this merely reflects the fact that the PGP and BPA both plan resources based on the worst historical flows. In the extremely unlikely case of less than critical water, both BPA and the

PGP may be unable to meet their firm loads. Thus, the metered requirements customers bear the same risks as computed requirement customers.

Basically, all parties agreed with BPA that computed requirements customers have greater operational flexibility than do BPA's metered requirements customers. Metcalf, BPA, E-BPA-32, 15-18; Hutchison, et al., WWPUD, E-WW-01, 39; Lauckhart, ICP, TR 7557; Cook, APAC, TR 7508-7509; Opening Brief, PGP, B-PG-01, 17; Power Sales Contract, sections 14 and 17. The issue is whether that flexibility is worth a premium as BPA suggests or whether existing risks and constraints regarding that flexibility make additional compensation for BPA unreasonable.

PGP is incorrect in its assertion that the proposed "availability charge" unilaterally takes away the generating utilities' flexibility. Generating utilities are still free to use their systems as they see fit. It is true that the charge may change the economics of those utilities' operation. However, the charge reflects real costs imposed upon BPA and therefore the change in economics is cost based and appropriate.

The basic point is that, even with the availability charge, BPA accepts greater risks for the actual computed requirements customers (all retail load variations, about half the displacement variations) than for metered requirements customers (just retail load varitions).

Issue #2

Are BPA's proposed "availability charges" appropriate and equitable to metered requirements customers and each of the three types of computed requirements customers?

Summary of Positions

Under cross-examination, BPA observed that displacement is both a revenue recovery problem and an equity problem. Metcalf, BPA, TR 5352. Other customers, i.e. metered requirements customers, are being asked to help pay the cost of critical water planning for computed requirements purchasers. Metcalf, BPA, E-BPA-32, 19. The WWPUD's agreed with BPA. Hutchison, et al., WWPUD, E-WW-01, 39; Opening Brief, WWPUD, B-WW-01, 64.

In contrast, the PGP felt that the availability charge (1) fails to ensure adequate revenue recovery, (2) does not distribute revenue requirement equitably among class members, and (3) does not encourage efficient use of resources. Garman, et al., PGP, E-PG-01, 20. Finally, the PGP claims that the readiness-to-serve argument applies equally to all PF customers. Garman, et al., PGP, E-PG-06R, 15.

APAC agreed in principle with the PGP, commenting that if BPA were to adopt such a charge it would be charging for energy which is not consumed. Cook, APAC, E-PA-02, 50.

Evaluation of Positions

Because BPA is not currently recovering the full costs associated with computed requirements purchasers' entitlement, BPA is proposing a rate design which will result in a sharing of the risks of revenue underrecovery. Metcalf, BPA, E-BPA-32, 27. "BPA can't avoid long-run incremental costs of resources if the generators, during periods when everyone has good water, displace their firm purchases from BPA." Metcalf, BPA, TR 5788. It was also noted that since NR power is more expensive than PF power, the revenue underrecovery from computed requirements purchasers will become acute as utilities begin to purchase under the NR rate. Metcalf, BPA, E-BPA-32, 19.

The WWPUD's felt it was appropriate to limit the benefits accruing to computed requirements purchasers from their ability to use their nonfirm energy in a discretionary manner. Hutchison, WWPUD, TR 6377. By sharing the savings, BPA's proposal is limiting, but not eliminating, the benefits enjoyed by computed requirements purchasers.

The PGP claimed that not only will an "availability charge" cause a disproportionate amount of harm, but also that imposition of such a charge is really only a band-aid approach to BPA's problem. Garman, et al., PGP, E-PG-01, 20; Opening Brief, PGP, B-PG-01, 14. The PGP's claim that the proposed charge will result in an unequal distribution of the revenue requirement among PF customers is unsupported by the record. In prefiled testimony, BPA noted that while forecasting revenues from computed requirements customer based on average water conditions would resolve revenue problems, it would not resolve equity problems. Metered requirements customers would still pay for critical water planning for computed requirements customers. Metcalf, BPA, E-BPA-32, 19-20. The evidence suggests that increasing the revenue recovery from computed requirements customers will be the most equitable solution to BPA's revenue recovery problem.

PGP's claim that the availability charge will not necessarily ensure revenue recovery is valid. However, BPA's goal with respect to these billing factors is not to eliminate all risks of revenue underrecovery, but rather to improve the equity between metered and computed requirements customers as well as to enhance the stability of BPA's revenue recovery from the computed requirements customers. Metcalf, BPA, E-BPA-32, 27.

Although the PGP is correct in asserting that the readiness-to-serve argument can apply to all PF loads and load variations, BPA is willing to accept the risk of retail load variations for all utility customers because these variations are outside the utilities' control. As pointed out in BPA's testimony, the computed requirements customers are using their contractual flexibility to their economic advantage. Metcalf, BPA, E-BPA-32, 18. The metered requirements customers are unable to do so. The proposed billing factors will tend to correct this existing inequity.

Issue #3

Is it appropriate for BPA to charge contracted computed requirements customers on a "take-or-pay" basis while applying different billing factors to purchases by actual and planned computed requirements customers?

Summary of Positions

In the initial proposal, BPA proposed charging contracted computed requirements purchasers on a "take-or-pay" basis in order to provide BPA with adequate financial protection for possible future capital investments which BPA might make on behalf of contracted computed requirements customers. Metcalf, BPA, E-BPA-32, 25.

The ICP objected to BPA's proposal, noting that a customer should not have to pay for capacity service if it is not requested. Lauckhart, ICP, E-IC-2, 6. Furthermore, the ICP claimed that BPA's proposed billing factors are contrary to the power sales contract. Lauckhart, ICP, E-IC-2, 5; Lauckhart, ICP, TR 7550-7552.

Evaluation of Positions

Under cross-examination BPA's witness observed that take-or-pay for contracted computed requirements customers will remove the risk of underrecovery with respect to displacement. Metcalf, BPA, TR 5354. This underrecovery results in revenue recovery problems particularly with respect to NR customers, who are all contracted computed requirements purchasers. Metcalf, BPA, E-BPA-32, 19. Therefore, it would be appropriate to impose billing factors that will help mitigate the problem.

However, the ICP's raised a sound concern with BPA's initial proposal, observing that under BPA's initial proposal BPA would impose a demand charge on NR customers irrespective of whether they take energy during heavy load hours. Lauckhart, ICP, E-IC-2, 4-5. Although the customers have the contractual right to take the power at any time of day, BPA does not, in other cases, assess a demand charge during off-peak hours, regardless of contractual right. Thus, under the initial proposal, there is no relief for a contracted requirements utility even if its energy use is entirely off-peak. By contrast, other computed requirements customers would only be subject to the Ratchet Demand (60 percent of the highest Computed Peak Requirement during the previous 11 billing months) under similar circumstances. While the take-or-pay concept has merit for energy or capacity taken during peak hours, this rate structure could have discouraged additional use of BPA's resources during this surplus period.

d. Legality of the Proposed Availability Charge

Issue #1

Are the availability charges in the initial proposal for computed requirements customers legal?

Summary of Positions

The PGP argues that the section 19(b) of the power sales contract states that computed requirements purchasers shall be billed for firm power delivered. Consequently, they believe that BPA's proposed charge, which would base the energy charge in part on the purchaser's right-to-purchase is illegal. Reply Brief, PGP, R-PG-01, 6-7.

The ICP concurs with the PGP that "[p]ursuant to section 19(b) of the contract, a contracted requirements customer is to pay for amounts of energy and peak requested by and scheduled to the customer." Lauckhart, ICP, E-IC-2, 5; Lauckhart, ICP, TR 7550-7552.

Evaluation of Positions

The PGP argues that the "availability charge" for computed requirements customers in the PF-83 rate is a violation of the terms of the metered requirements and computed requirements power sales contract (Contract). Reply Brief, PGP, R-PG-01, 57. The availability charge is designed to enhance BPA's revenue stability in the face of increasing displacement of firm purchases from BPA by computed requirements customers through use of their own nonfirm energy or nonfirm energy purchases. Such displacement of firm purchases from BPA leads to significant revenue underrecovery because of BPA's frequent inability, given market conditions, to sell the displaced power at a rate which will recover BPA's fully allocated costs. BPA, E-BPA-7, 29-30. However, BPA is contractually obligated to stand ready to supply the difference between these generating utilities' loads and the critical water capability of their resources, whether or not the loads are actually placed on BPA. BPA, E-BPA-7, 29. The availability charge is an energy billing factor which is a weighted average of the purchaser's monthly Computed Energy Maximum and the Measured Energy. BPA, E-BPA-7, 31-32. The Computed Energy Maximum is the amount of energy which a computed requirements customer is entitled to schedule or receive from BPA. The effect of the charge is to charge these customers partially on the basis of actual deliveries and partially on the basis of how much the customer is entitled to take from BPA.

The PGP argues that section 8(i) of Exhibit B of the Contract, particularly in view of the interpretation given to that subsection by the Settlement Agreement in PPC v. Johnson, Ninth Circuit No. 81-7806, prohibits BPA from assessing a charge "for power which they [computed requirements customers] are not entitled to schedule or receive." Reply Brief, PGP, R-PG-01, 6. Section 8(i) provides as follows:

> Rates for Firm Power sold pursuant to sections 14 and 17 of the utility power sales contract shall be established in such a fashion that the Purchaser shall not be billed for Firm Power during any 12 month rate period in excess of the amount which the Purchaser was entitled to take during such 12-month period.

The interpretation given to this section by the Settlement Agreement provided:

> Section 8(i) of the General Contract Provisions has the following meaning and shall be interpreted as follows:
>
> (1) Purchaser will not be charged for energy or capacity which it is not entitled to schedule or receive each billing month under this contract except as permitted in (2) below;
>
> (2) The interpretation in (1) above shall not be interpreted to preclude Bonneville from developing rate procedures which allow uniform

billing over a rate period not to exceed the cost allocated to the sum of monthly capacity amounts the Purchaser had a right to schedule or receive during any 12-month rate period.

(3) The Purchaser shall not be assessed a customer or minumum charge, or any similar or other charge, during any Operating Year it is not entitled to schedule or receive energy or capacity (emphasis added).

The PGP is correct in its interpretation of section 8(i) that BPA is prohibited from charging for energy which a computed requirements customer is not entitled to schedule or receive. It is mistaken, however, in its allegation that the availability charge violates that prohibition. The availability charge is directly related to the amount of power BPA must make available to the utility under its power sales contract; i.e., the amount to which the utility is entitled.

A contracted computed requirements utility is entitled to take the full amount of its contracted computed requirements upon which the availability charge is computed. Both actual computed requirements and planned computed requirements utilities are entitled to schedule or receive during a month their Computed Energy Maximum, from which the availability charge is computed. The Computed Energy Maximum is, in effect, equal to the monthly total of the hourly difference between the utility's firm loads which BPA is obligated to serve and the Assured Capability of the resources committed to its load. For an actual computed requirements customer, the computed energy maximum is computed after the end of each month using actual figures for the utility's firm load. It thereby takes into account load decreases caused by weather, economic and other variables. For a planned or contracted computed requirements customer, the effect of such load variations can be reflected when the customer's load forecast is updated.

Contrary to the PGP position, the wording of section 8(i) clearly supports the Administrator's authority under the Contract to establish an availability charge. The intent of this provision is that rates may be set to charge for power up to the amount the Purchaser is entitled to take. If the Administrator is required by other provisions of the Contract to bill only for delivered energy, as the PGP asserts, section 8(i) becomes superfluous. However, all terms of a contract must be considered together and every clause, sentence or provision should be given effect consistent with the main purpose of the contract. Oliver-Mercer Electric Cooperative v. Fisher, 146 N.W.2d 346, 352 (N.D. 1966). It should be noted that the wording of section 8(c), quoted below, refers to the obligation of the Purchaser to pay for electric power and energy "made available".

The PGP also argues that section 19 of the Contract prohibits BPA from billing for energy on any basis other than actual deliveries made to the customer.

(19(b)) The Purchaser shall pay Bonneville each Billing Month for all amounts described in the following paragraphs in accordance with the terms of the rate schedules specified below, the payment provisions of the General Contract Provisions Exhibit and of the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit.

(1) For Firm Power delivered hereunder in accordance with the following:

(a) If the Purchaser is a public body, cooperative or Federal Agency, payment shall be at the rate specified in the Priority Firm Power Rate Schedule for the Purchaser's Measured Demand and Measured Energy . . . . (emphasis added).

Measured Energy for computed requirements customers is defined in section 3(bb) as "the sum of the Measured Amounts for all hours in a Billing Month". Measured Amounts is defined in section 3(z) to be generally the amounts of Firm Power delivered to the Purchaser. The PGP asserts that the use of the term "delivered" in section 19(b)(1) and Measured Energy in section 19(b)(1)(A) limits BPA to charging only for energy actually delivered to the Purchaser.

Opposed to the PGP reading of section 19 are numerous clear instances in the Contract of an intent to retain maximum ratemaking flexibility:

(19(a)) The determination of amounts due to Bonneville by the Purchaser . . . shall be made according to . . . the Wholesale Power Rate Schedules and General Rate Schedule Provisions Exhibit. . . as such exhibits may be amended or replaced. . . .

(19(b)) The Purchaser shall pay Bonneville each Billing Month for all amounts described in the following paragraphs in accordance with the terms of the rate schedules specified below . . . .

(1) For Firm Power delivered hereunder in accordance with the following:

(a) If the Purchaser is a public body, cooperative or Federal Agency, payment shall be at the rate specified in the Priority Firm Power Rate Schedulef or the Purchaser's Measured Demand and Measured Energy . . . . (emphasis added).

Section 8 of the General Contract Provisions, Equitable Adjustment of Rates, states:

(8(a)) Bonneville shall establish, periodically review and revise rates for the sale and disposition of electric power, capacity or energy sold pursuant to the terms of this contract. Such rates shall be established in accordance with applicable law.

* * * * *

(8(c)) The Purchaser shall pay Bonneville for the electric power and energy made available under this contract . . . at the rate specified in any rate schedule available at the beginning of [the rate period] for service of the class, quality, and type provided for in this contract, and in accordance with the terms thereof . . . Rat es shall be applied in accordance with the terms thereof . . . and the terms of this contract. (emphasis added).

This full deference to the rate schedules as the only determinants of the financial obligation to BPA is similar to the contractual language which the United States Supreme Court has held to retain the full ratemaking discretion of the seller. See the discussion of this and other cases in BPA counsel's discussion of the legality of the proposed DSI customer charge. The only instance of a general limitation upon the Administrator's ratemaking flexibility, other than specific negotiated limitations not relevant to this issue, is that found in section 8(e) of the General Contract Provisions:

> Bonneville's wholesale power rates established on any Rate Adjustment Date shall be developed consistent with the provisions of section 7 of P.L. 96-501.

Section 7 of Pub. L. No. 96-501 imposes no restrictions on the Administrator's authority to impose an availability charge.

Devices such as minimum bills and availability charges are rates. Mobil Oil Corp. v. T.V.A., 387 F. Supp. 498 (N.D. Ala. 1974). This has been a judicial interpretation since at least 1939. Great Northern Ry. Co. v. Armour & Co., 26 F. Supp. 964 (N.D. Ill. 1939); Avant Gas Service Co. v. Corporation Commission, 89 P.2d 291 (Okla. 1939). The generalized retention of the right to establish new rates includes the right to establish a rate known as an availability charge.

These instances of express deferral to the rates and the ratemaking process and the clear indication of intent provided by section 8(i) clearly show the lack of any contractual intention to impose the restriction asserted by the PGP. Even if the contract is construed to be ambiguous, however, the available extrinsic evidence of the contractual intent requires the conclusion that the Administrator did not negotiate a contract which restricted his authority to impose an availability charge. The Contract Official Record (COR) does evidence some early concern on the part of the utility negotiators as to BPA's ability under the contract to change the rate design for computed requirements customers. Both the PPC and the ICP wanted "to limit BPA's future ability to adopt rates that will make these contracts into take or pay contracts." COR, 006657. The same document stated that the ICP's suggested compromise on this issue "would make BPA obligated to deliver any power they are obligated to pay for." This compromise position in fact became the position of both the ICP and the PPC for the rest of the negotiations and resulted in section 8(i) of the GCP's. The ICP's position was that "purchasers should be assured the right to schedule the full amount of power and energy they are being billed for in any given month." COR, 006687. The PPC position was that "no utility customers should pay for power which it does not have a right to take." COR, 006697. No indication exists in the COR, except for the early "pre-compromise" statement on take-or-pay contracts, that the utility negotiators were concerned about a charge based on the amount of energy which the Purchaser could have taken.

BPA's negotiating position on this matter is significant. Its position was that "under the present rate structures, this issue is not a problem. BPA's position has been that it is not acceptable to fix rate structures by terms in the contract." COR, 006697; COR, 006687. Obviously an exception to that position was made in the case of section 8(i). The exception was, however, expressly set out in the contract. Any other exceptions also would be expected to be expressly stated in the Contract.

The PGP assertion that section 19 of the Contract was intended to limit the Administrator's ratemaking authority is not supported either by the express terms of the Contract or by the record of the actual negotiations of the parties. This should be no surprise. The Contract is a 20-year commitment of BPA to supply energy. One would expect to find more evidence than that offered by the PGP of a decision which could have such momentous impacts on the financial future of the agency.

e. Computation of the Computed Requirements Billing Factor

BPA designed the energy billing factor for actual and planned computed requirements customers so that "the portion of the rate which varies with energy actually taken is equal to the marginal revenue which BPA would receive from an alternative nonfirm sale of displaced energy. This is accomplished by changing the energy billing determinant [factor] from measured energy to a weighted average of measured energy and the computed energy maximum. The weighting factor for measured energy is equal to the marginal nonfirm energy revenue divided by the Priority Firm Power energy charge." Metcalf, BPA, E-BPA-32, 21-22.

Since no other parties expressed an opinion relating to BPA's proposed methodology, BPA has adopted the methodology presented in the initial proposal.

f. Other Solutions to BPA's PF Revenue Recovery Problem

Issue #1

Should BPA take a different approach to the revenue stability problem from the one taken in the initial proposal?

Summary of Positions

BPA's initial proposal included an "availability charge" for actual and planned computed requirements customers and a "take-or-pay" arrangement on both demand and energy for contracted computed requirements purchasers. BPA did not change its proposal for actual and planned computed requirements customers in its rebuttal testimony, but a few (non-preferred) options were identified. Metcalf, BPA, E-BPA-46R, 6-8.

The parties suggested three alternative approaches (other than PF reclassification or a surcharge, both discussed elsewhere) to the revenue shortfall problem as it relates to computed requirements customers (1) eliminate the Spill rate; (2) impose a customer charge; and (3) increase the demand ratchet. The WWPUD's suggest that BPA increase the Spill rate to cause other generators to sell their nonfirm or change billing factors as BPA originally proposed. Hutchison, et al., WWPUD, E-WW-01, 41; Hutchison, WWPUD, TR 6346; Opening Brief, WWPUD, B-WW-01, 65. The PGP concurred with the WWPUD's recommendation to eliminate the Spill rate. Garman, et al., PGP, E-PG-01, 23; Opening Brief, PGP, B-PG-01, 17. As a nonpreferred alternative the PGP suggested a surcharge (see the section entitled "Revenue Shortfall Adjustments"). Garman, et al., PGP, E-PG-01, 22; Garman, PGP, TR 6521-6525. Finally, APAC objected to BPA's proposal and suggested a customer charge or increased demand ratchet, provided additional revenue stability measures are required. Cook, APAC, E-PA-2, 49.

Evaluation of Positions

BPA identifed several possible alternatives to the initial proposal. One possibility would be to have two PF rates, one for computed requirements purchasers and the other for metered requirements customers. BPA could also charge for demand based on the computed maximum requirement (vs. the computed peak requirement). However, the options of having two PF rates and adding a customer charge were not explored sufficiently on the Record as to enable BPA to adopt them. Other options relating to billing demand include increasing the ratchet from 70 percent to 100 percent and/or extending the ratchet period from 11 to 42 months. Finally, BPA could adopt a deferral adjustment clause if actual revenue recovery differed significantly from the forecast. Metcalf, BPA, E-BPA-46R, 6-8.

PGP noted that an increase in the Spill rate (or elimination of the rate altogether) might well cause a reduction in displacement by computed requirements customers. Garman, PGP, TR 8292. This displacement would be reduced because there would be "a reasonable market available for the generating utilities' nonfirm energy." Opening Brief, PGP, B-PG-01, 17. However, it is not clear that such a result would necessarily follow. Even if BPA's Spill rate were eliminated, there would still be periods when the marginal revenue from nonfirm sales for a computed requirement customer would be less than the PF energy charge, because of limited intertie capacity. Metcalf, BPA, TR 7806-7807.

APAC's suggestion to increase the demand ratchet is a reasonable option, also advanced by BPA. Metcalf, BPA, E-BPA-46R, 6-8. However, increasing the demand ratchet could potentially penalize utilities that may not be displacing purchases from BPA but may, because of fluctuating loads and resource capabilities, have lower capacity requirements in some month following the month in which the ratchet is determined. The initial proposal has the advantage that it protects some demand costs and some energy costs, sharing, with customers, the risk of revenue underruns from both categories of costs.

APAC's other suggestion, that BPA impose a customer charge, may not be appropriate assuming that the customer charge has no relationship to the amount of power that a utility is entitled to take. The General Contract Provisions, attached to the power sales contract, address BPA's rights with respect to setting billing factors for computed requirements customers. That section notes that billing is limited to charging a customer for its entitlement of demand and energy. Power Sales Contract, section 8(i) of Attachment B.

g. BPA's Resolution of the Computed Requirements Question

Issue #1

What billing factors should BPA use for each type of computed requirements customer?

Summary of Positions

BPA and the WWPUD's contend that it is appropriate to assess an "availability charge" on computed requirements purchasers.

The PGP argues that BPA should base its billing factors for all computed requirements customers on Measured Demand and Measured Energy. APAC and the DSI's also contend that the proposed availability charge is inappropriate.

Evaluation of Positions

The Evaluation of the positions of BPA and each of the parties with respect to each of the issues having to do with the availability charge has been presented in the foregoing sections a-f.

Decision

BPA's decision is based on consideration of all the factors discussed in sections a-f, above. BPA has included the availibility charge outlined in the initial proposal for all computed requirements purchasers: actual, planned, and contracted. The take-or-pay charge for contracted computed requirements customers which BPA included in the initial proposal has been eliminated. The reasoning behind BPA's decision with respect to this issue is presented below.

Causes of BPA's Revenue Recovery Problem

Displacement by computed requirements purchasers has recently resulted in significant revenue underruns, especially as a percentage of the forecast revenues from that class. These load underruns also occur primarily during spill periods when BPA is unable to recover much revenue from the displaced power. It is true that the ratio of underruns from computed requirements customers to total revenue underruns is fairly small, but that only reflects the relatively small amount of the BPA revenue requirement assigned to the computed requirements customers.

Effects of BPA's Proposal

The proposed charge will raise the overall purchased power costs of the computed requirements customers. The "fine-tuning" problem (the computed requirements customers' inability to fine-tune their systems to avoid both the Unauthorized Increase and the "availability" charges completely) is minor and for the actual computed requirements customers can be alleviated through use of the flexibility account and the Relief from Overrun Exhibit to the power sales contract. The effects of BPA's proposed availability charge are appropriate and represent resource costs that a utility which owns all its own resources cannot avoid.

As for the effects of BPA's proposal on conservation, three possible effects have been identified: (1) there might be a reduction in the incentive to undertake conservation as a result of the uncertain short-term effects of conservation on loads; (2) there could be an increase in the incentive to undertake conservation because of a decrease in weather-sensitive loads; and (3) there might be an increase in the incentive to undertake conservation because of the higher cost of BPA power. There is no evidence that any of these three possible effects is significant. Even if these effects were significant, all represent cost considerations that are appropriate in assessing resource alternatives. If anything, the proposed billing factors should improve the price signals to generating utilities concerning the cost of BPA power and the cost of their own resources, especially resources with variable output.

BPA's proposed billing factors for computed requirements customers will continue to permit, from an economic point of view, a reasonable degree of operational flexibility. BPA can find no evidence on the record that the change in billing factors would reduce the operational or economic efficiency of the region's power system.

Equity Issues

Computed requirements customers, unlike metered requirements customers, can elect to displace purchases from BPA. It is appropriate for BPA to reflect the differences in operational flexibility between the two types of customers in the billing factors. The billing factors will ensure that metered requirements customers do not bear the total costs of critical water planning for computed requirements customers.

The billing factors for contracted computed requirements customers have been modified to be consistent with those for actual and planned computed requirements customers. Thus, in the 1983 wholesale power rates, BPA will be selling power to all computed requirements customers under the same terms. When BPA begins acquiring expensive resources to serve the NR customers, it will be appropriate to reassess the NR billing structure.

Legality of the Proposed Availability Charge

Although section 19(b) of the power sales contract states that BPA shall charge computed requirements purchasers for the amount of Measured Energy, other sections of the same contract (see the General Contract Provisions, section 8(i)) clearly demonstrate that the language in section 19(b) was not intended to be restrictive. Consequently, the proposed availability charge is legal, despite PGP's and the ICP's claims to the contrary.

Computation of the Computed Requirements Billing Factor

BPA has continued to develop the computed requirements billing factor for energy in the same manner as in the initial proposal. No alternative proposals were presented on the Record.

Other Solutions to BPA's Revenue Recovery Problem

BPA has not adopted any of the alternative "revenue stability" proposals. It is more appropriate for BPA to charge utilities for the energy obligations they cause BPA to incur, than to change the demand ratchet. It is unclear whether elimination of the Spill rate would solve the displacement problem for PF customers. It is very unlikely that it would do so for the NR class.

3. Adjustment Clauses

BPA includes adjustment clauses in its rates in order to adjust rates automatically in response to changes in the actual costs of major expense items over which BPA has little control.

a. Exchange Adjustment Clause

The Exchange Adjustment Clause (EAC) is included in the PF, IP, CF, and NR rates. Exchange resources are assigned to loads served under these rates. The adjustment is in the form of a rebate or surcharge if the actual average cost of exchange resources during the period November 1, 1983, through June 30, 1985, differs from that forecast.

Issue #1

Does the Exchange Adjustment Clause (EAC) effectively adjust for changes in net exchange costs?

Summary of Positions

In the initial proposal, the EAC was included in rates which are assigned exchange resource costs. The EAC was based on the average system cost (ASC) of the non-deemer IOU's. The EAC is implemented by adjusting each customer's bill by the product of: (1) the ratio of exchange costs to the total revenue requirement for that class of service; (2) the percentage of the exchange resource cost of the specified IOU's to the total forecast cost of exchange resources'; (3) the percentage under- or overestimation of average exchange costs of the specified IOU's; and (4) the customer's total bill under the rate schedules for each rate period. BPA, E-BPA-7, 33-34. The EAC in the initial proposal was based on five nondeemer IOU's which represented 63.2 percent of the total exchange cost and 95.5 percent of the net exchange cost. In supplemental testimony there were seven nondeeming IOU's on which the EAC would be based. Metcalf, BPA, E-BPA-32S, Attachment 2, 6.

The ICP contends that the EAC does not adequately reflect the two main reasons for deviation of actual exchange resource cost from that forecast: changes in ASC and changes in loads. To correct for this problem, the EAC calculation should be based on the average cost of exchange resources for all utilities. They suggested more complex changes including a balancing account to carry forward any under- or overcollection of exchange cost due to changes in customer loads. Kuns & Kellerman, ICP, E-IC-01, 10-11.

Evaluation of Positions

The ICP argues that no provision has been made for inclusion of public or deemer IOU exchange cost changes and the associated change in the average cost of the exchange. Thus, changes in ASC and in loads, the two main reasons for deviation from forecast, are not adequately represented. The simplest method of correcting this is to include the average exchange cost for all utilities. Kuns & Kellerman, ICP, E-IC-01, 10-11.

BPA based the EAC on the ASC of the non-deeming IOU's because they represent the major portion of the net costs of the exchange; that is, they have the greatest effect on BPA's net revenue. Metcalf, BPA, E-BPA-32, 28. The deemer IOU's have no impact on net revenue and the public agencies have a minor impact. Public agencies' ASC's are close to the PF rate. Deviations in public agencies' ASC's are not as simple to account for as the ICP implies. If the amount of public agency exchange load were greater than forecast, BPA's net costs would increase. However, the average cost of the exchange would decrease which, in turn, effectively reduces rates through the EAC. Metcalf, BPA, E-BPA-32, 28-30.

The parties have correctly noted that BPA's proposed EAC would reflect only a portion of exchange cost deviations. There are two reasons why the EAC is designed in this manner. First, BPA designed the EAC to be implemented monthly because some customers expressed a preference for a monthly adjustment. Metcalf, BPA, E-BPA-32, 28. However, it is very difficult to incorporate load changes in an adjustment clause which operates monthly because of monthly load variations and the seasonality of the PF rate. In addition, since an EAC that tracks changes in loads and costs must be based on the net cost of the exchange, these two cited factors would make a monthly EAC highly variable. The monthly option was implemented for the IP-2 rate because the DSI's believed that BPA had seriously overestimated exchange costs; no large disagreement exists this year. In the 1983 rate proceeding the DSI's have asserted that BPA has slightly underestimated exchange costs. Schoenbeck, DSI, E-DS-20R, 2.

Second, if the EAC is based only on the average cost of the exchange, it must be based on the cost of a selected predetermined set of utilities. Otherwise, it could have the perverse results of lowering rates while BPA's net exchange costs rise. Metcalf, BPA, E-BPA-32, 28-29.

Decision

The EAC has been redesigned to track changes in the net cost of the exchange on BPA. Thus, it varies with both loads and costs. The monthly option contained in the initial proposal has been eliminated because the reformulated EAC would make the monthly adjustment far more complicated and variable.

Issue #2

Should BPA design the EAC to track the effect of changes in the size of exchange loads on the allocation of exchange resource costs to the various rate pools?

Summary of Positions

BPA's proposed EAC was based on the allocation of exchange costs in the rate case, with no adjustments to recognize the change in allocation brought about by a change in loads. The PPC, the WWPUD's, and the DSI's are concerned about the rate effect of including public agencies (specifically, Snohomish County PUD) in the exchange versus the ETCA. The WWPUD's and the DSI's propose amending the EAC to adjust for changes in loads as well as cost. The WWPUD's assert that this change in the EAC would allow BPA to exclude Snohomish from the exchange and not penalize PF customers, and to recover sufficient revenue if Snohomish were to enter the exchange. Hutchison, et al., WWPUD, E-WW-02R, 12-13; Mundorf, WWPUD, TR 4537-4539. The DSI's assert that a factor in the EAC that adjusts rates for changes in exchange loads would eliminate game-playing by public agencies. Schoenbeck, DSI, E-DS-8, 12-13.

The PPC proposes an ETCA/EAC to neutralize the adverse effects of a BPA decision concerning whether a utility will opt for the ETCA or exchange program. Under this proposal, the Administrator would initially decide whether a utility is included in the exchange or ETCA program. For the final rate proposal and Period A rates, BPA would recalculate: (1) the PF load with respect to its exchange component; (2) the total and average costs of the exchange; and (3) the PF rate and other rates affected by the ETCA/exchange decision. BPA could establish in advance the exchange load for each utility with and without the exchange decision, and the costs to use for either choice. Wolverton & O'Meara, PPC, E-PP-02R, 6-8; Opening Brief, PPC, B-PP-01, 19-21.

Evaluation of Positions

The PPC, the WWPUD's, and the DSI's recommend that BPA amend the EAC to adjust cost allocations for changes in exchange loads. If BPA's forecast of exchanging utilities is incorrect, the rates should differ from what BPA calculates for the final proposal. The parties are particularly concerned about the inclusion of Snohomish County PUD in the exchange instead of the ETCA program. The WWPUD's want to exclude Snohomish from the exchange for the final rates, and to adjust rates if they enter the exchange during the rate period by factoring into the adjustment the change in the load/resource balance that would occur. Hutchison, et al., WWPUD, E-WW-02R, 12-13. The DSI's assert that such a change in the EAC would eliminate game-playing by the public agencies. Schoenbeck, DSI, E-DS-8, 12-13. The PPC proposed an ETCA/EAC to neutralize the adverse effects on PF customers of a BPA decision concerning whether a utility will opt for the ETCA or exchange program. Wolverton & O'Meara, PPC, E-PP-02R, 6-8.

The EAC is designed to enhance BPA's fiscal integrity by adjusting for changes in the net cost of the exchange, not by recalculating the cost allocations made in the rate case. BPA forecasts loads and costs based on the best information available. BPA has carefully analyzed the Snohomish situation and has determined that it will be to Snohomish's benefit to exchange during the rate period. See Chapter III, Residential Exchange and ETCA Cost Projections. The change to the EAC that is suggested by the parties is equivalent to recalculating all the rates; i.e., a new load/resource balance, COSA, and WPRDS. This alternative is considerably more complex than the proposed EAC. One indication of the complexity is that no party proposed specific EAC language along with a specific method for calculating the adjustment.

Decision

The EAC proposed by the PPC and DSI's would widen the purpose of the clause from reducing revenue instability to changing the resource pool-load pool cost allocation according to actual conditions. This would make the clause much more complicated and difficult to administer. As with the allocation of the deferral, it is extremely difficult to redo cost allocations based on actual conditions. Therefore, the EAC does not include a provision to recalculate the allocation of exchange costs.

Issue #3

Should the method and procedures for implementing the EAC be altered?

Summary of Positions

BPA offered a choice of a monthly or annual adjustment in the initial proposal. Metcalf, BPA, E-BPA-32, 28. The draft decision eliminated the monthly adjustment due to a change in the EAC formulation. Evaluation of the Record, 161. Other aspects of the EAC are the adjustment trigger of .001 and a 30-day period to pay the adjustment.

The DSI's contend that BPA must offer to implement the EAC on a monthly basis consistent with the initial proposal. Reply Brief, DSI, R-DS-01, 16-17.

PP&L suggests that implementation of the EAC could reduce BPA revenue stability if BPA is underrecovering revenue. A possible solution is that the EAC could be imposed only if BPA was not realizing its revenue requirement. Wood, PP&L, TR 5379-85; Opening Brief, PP&L, B-PL-01, 46-47. PP&L also asserts that the EAC trigger of .001 is too low. Wood, PP&L, TR 5385-5386; Opening Brief, PP&L, B-PL-01, 47.

PP&L urges that BPA automatic adjustment clauses accommodate IOU retail regulatory problems in the following ways: (1) no surcharges should be imposed retroactively, or alternately; (2) an adjustment clause should not be included in firm capacity schedules; (3) 60 days advance notice of a surcharge is required; and (4) rate adjustments should not be made more frequently than once in a 6-month period. Opening Brief, PP&L, B-PL-01, 48-49.

Evaluation of Positions

The DSI's argue that BPA must offer a monthly EAC option as initially proposed. They state that no party objected to the monthly option or proposed it be removed as an option. No evidence was presented that the option caused "additional complications," the reason BPA gave for eliminating it. The DSI's also cite the pending renegotiation of the ASC methodology as a reason to maintain the monthly option in order to permit the rates to immediately reflect changes in the methodology. Reply Brief, DSI, R-DS-01, 16.

The DSI's also discuss the institution of the monthly option in the 1982 rates. This option was instituted after the rates were filed with FERC for interim approval. The DSI's argue "that the annual adjustment produced major cash flow and management difficulties for the DSIs" which the monthly option remedied. Reply Brief, DSI, R-DS-01, 16.

BPA maintains that the Exchange Adjustment Clause as well as the monthly option was implemented because the DSI's believed that BPA had seriously overestimated exchange costs. 1982 Administrator's Record of Decision, 89-90. In fact, BPA's notice of the monthly option to its customers specifically stated that the reason this option was offered was because the DSI's believed that the ASC and resulting IP-2 rate were seriously overstated. However, it appears there is no major disagreement over the level of the exchange costs used in development of the IP-83 rate. Evaluation of the Record, 71-80. The EAC is as likely to necessitate a rebate as a surcharge.

The primary reason BPA eliminated the monthly option in its draft decision was due to the reformulation of the EAC. The EAC adjusts for changes in net exchange costs; that is, changes in exchange loads and costs. Many parties did not consider the EAC initial proposal to be adequate. The ICP argued that the adjustment did not adjust for changes in ASC and changes in load. Kuns & Kellerman, ICP, E-IC-01, 10-11. The PPC, WWPUD's and the DSI's argue that the EAC should track the effect of changes in the size of exchange loads on the allocation of exchange resource costs to the rate pools. Wolverton & O'Meara, PPC, E-PP-02R, 6-8; Hutchison, et al., WWPUD, E-WW-02R, 12-13; Schoenbeck, DSI, E-DS-8, 12-13. As discussed in Issues 1 and 2 above, BPA has reformulated the EAC to adjust for changes in the net cost of the exchange. Maintaining a monthly option could result in monthly adjustments that run counter to the annual adjustment. Due to the seasonal differentiation of the rates and monthly load variations, a monthly adjustment would be complex and highly variable. Thus, it is due to the reformulation of the EAC in response to comments from parties that the monthly option has been removed.

The annual adjustment will reflect any changes in the ASC methodology. The official notice of the intent to reformulate the ASC methodology has not been published at this writing. It is impossible to forecast when the process will be completed and a new method implemented. A new ASC method could make calculation of a monthly Exchange Adjustment far more administratively complex.

The DSI's assert that no party objected to the monthly option or proposed it be removed as an option. They also contend that BPA took away the DSI's option of making a record and cross-examining on such a proposal. Reply Brief, DSI, R-DS-01, 16-17. However, BPA is eliminating the monthly option due to the reformulation of the EAC. The EAC is being designed based on a party's comments and proposals. Kuns & Kellerman, ICP, E-IC-01, 10-11. Parties want to be able to propose alternative methods without fully developing a proposal. If BPA is to develop a party's proposal fully, it may be necessary to alter some aspect of the rate proposal which was not specifically addressed by the party. Otherwise, parties would need to fully develop every alternative to reveal all consequences of their recommendation. Such a requirement would be extremely burdensome to all.

PP&L asserts that the EAC does not promote revenue stability and should be eliminated. They cite the 1982 EAC as an example of BPA paying out large sums of money as a result of the exchange adjustment during a time that BPA was running a serious revenue deficiency. The EAC would also allow BPA to collect money when it has a net income greater than forecast. PP&L recommends that BPA implement an EAC surcharge only if BPA is not realizing its revenue requirement, or alternately, eliminate the EAC. In addition, PP&L states that the EAC trigger is too low; BPA could tolerate deviations far greater than that proposed in the EAC. Wood, PP&L, TR 5379-5386; Opening Brief, PP&L, B-PL-01, 46-47.

BPA agrees that there will be times when events such as that described by PP&L will occur. That is, BPA will rebate money under the EAC when it is not recovering its forecasted revenue requirement. However, BPA contends that the EAC actually increases the probability that costs will match revenues and decreases the probability that events described by PP&L will occur. Metcalf, BPA, TR 5384. The ability to track changes of a major cost component and adjust revenues to account for such cost deviations will allow a greater probability of costs matching revenues. Metcalf, BPA, TR 5381-5382. In regard to BPA rebating money when it is not recovering its forecast revenue requirement, it appears inequitable to make certain rate classes responsible for paying for such an underrecovery when a major cost component of their rate is significantly lower than forecast. BPA agrees that the trigger of 0.001 is lower than necessary, and BPA could tolerate a greater level of deviation in exchange costs. While BPA agrees the EAC trigger is too low, it is necessary to consider the cumulative impact of the deviation allowed in the Supply System Adjustment Clause and the level of deviation allowed in the EAC.

PP&L is further concerned that BPA should not institute an adjustment clause that causes a shift of BPA costs onto utility stockholders. First, they assert that BPA should not impose a surcharge retroactively because retail regulators generally bar retroactive recovery of regulated utility costs, but make exceptions if a balancing account is in effect for the period to which the surcharge applies. PP&L has such an account for reimbursement under its Residential Purchase and Sale Agreement. Alternately, PP&L suggests that the EAC should not be included in the CF-83 rate because they do not have a balancing account with respect to payments for BPA firm capacity. Opening Brief, PP&L, B-PL-01, 48-49.

Including the EAC in the CF-83 rate introduces only a small amount of uncertainty in PP&L's forecast of costs for BPA capacity. As PP&L itself notes, the EAC may well result in rebates rather than surcharges, as it did for the current rate period. Some uncertainty is a fact of life for regulated as well as unregulated utilities. The EAC is implemented on a retroactive basis to limit administrative complexity and increase accuracy. The only witnesses to propose a balancing account did not explain how such a concept could be included in BPA's exchange adjustment clause.

PP&L also wants BPA to provide at least 60-days advance notice of any surcharge in order to obtain regulatory approval for the necessary relief in as many as six retail jurisdictions. Finally, PP&L argues that rate adjustments more frequent than once in a 6-month period may be considered unacceptable by retail regulatory bodies. Opening Brief, PP&L, B-PL-01, 49.

The initially proposed EAC was to be implemented only twice for the 20-month rate period unless customers opted for a monthly adjustment. The draft decision in the Evaluation of the Record, 161, eliminated the monthly option. The EAC would be implemented once for the 8-month period of November 1983 through June 1984 and once for OY 1985. Thus, there will not be an Exchange Adjustment more frequently than once in a 6-month period. In addition, the initial EAC proposed that the adjustment be paid within 30 days of the date on the adjustment notice whether it was a surcharge or rebate. BPA understands PP&L's desire to have a 60-day notice regarding an EAC surcharge. However, it is BPA's policy to have all bills paid within 30 days, in conformance with the Prompt Payment Act. PP&L has not cited persuasive evidence demonstrating that BPA should deviate from standard accounting procedure in this one instance alone.

Decision

The monthly option will be eliminated from the EAC. The reformulated EAC makes the monthly option infeasible because of the seasonal differentiation of rates and monthly load variations. BPA will not eliminate the EAC as recommended by PP&L because it allows for a better tracking of costs with revenues. BPA is continuing the policy of making a retroactive adjustment, but is allowing for a higher level of deviation before instituting an adjustment. The EAC allows for a deviation from actual costs of more than $20 million (assuming BPA collects its forecast revenue requirement) before triggering.

BPA notes that rates which have been assigned exchange resource costs also will be adjusted if BPA is ordered to adjust average system cost for an exchanging utility by order of the Federal Energy Regulatory Commission or the U.S. Court of Appeals for the Ninth Circuit. This has always been BPA's intention, although some ambiguity was created by language in the 1982 Exchange Adjustment Clause. BPA intends to comply with orders of the Federal Energy Regulatory Commission and the courts concerning average system costs and reflect such compliance in the power costs of its customers.

b. Supply System Adjustment Clause

The Supply System Adjustment Clause adjusts for changes in the cost of Supply System WNP-1, -2, and 70 percent of -3 from the forecast costs used to develop rates for the test period.

(1) Constraints

Issue #1

What costs should be passed on to BPA's customers through the Supply System Adjustment Clause (SSAC)?

Summary of Positions

In the initial proposal, BPA proposed a SSAC to adjust for increases or decreases in BPA's share of costs of the Supply System Plants WNP-1, -2, and -3, compared to the costs used to determine the revenue requirement for OY 1984 and 1985. The adjustment accounts for differences in:

a. the actual OY 1984 Supply System net funding requirement for the three plants (i.e., BPA's share of the costs) compared to the cost forecast for OY 1984, and

b. BPA's share of the OY 1985 Supply System Annual Budgets for the three plants submitted in the spring of 1984, compared to the cost forecast for OY 1985. BPA, E-BPA-7, 34-35; Metcalf, BPA, E-BPA-32, 29.

In supplemental testimony, BPA limited the cost increases included in the SSAC to cost increases necessary to maintain the construction status of the three plants assumed in the cost used to develop rates. The forecast Supply System cost reflects preservation of WNP-1, completion and start-up of WNP-2, and ramping down construction and placing in minimum preservation WNP-3. Metcalf, BPA, E-BPA-32S, 2-3.

In prefiled testimony, APAC expressed concern that the SSAC would be used to pass on cost changes pursuant to a decision made after the close of the hearings to change the method of financing the three Supply System plants. Specifically they objected to using the SSAC to pass on cost changes caused by financing the plants through revenue instead of the projected bond sales assumed in the initial proposal. Cook, APAC, E-PA-02, 65. The PPC proposed limiting the OY 1985 adjustment to the difference between current projected and updated projected rates of interest and inflation. Also, the PPC suggested that the SSAC should include, as a mitigating factor, revenues from WNP-2 test energy. Wolverton & O'Meara, PPC, E-PP-01, 7-9.

BPA proposed a lower limit before triggering the Supply System adjustment, but not an upper limit. BPA, E-BPA-7, RC-112. Both the PPC and the WWPUD's propose that a ten percent ceiling be established on the increase in Supply System cost from forecast cost that would pass through to BPA's customers. Wolverton & O'Meara, PPC, E-PP-01, 9; Hutchison, et al., WWPUD, E-WW-01, 37; Hutchison, et al., WWPUD, E-WW-02R, 27.

Evaluation of Positions

The PPC, and the WWPUD's do not oppose a mechanism designed to adjust rates to reflect reasonable changes in Supply System costs, however they voiced concern that the SSAC proposed by BPA is "too open-ended." Wolverton & O'Meara, PPC, E-PP-01, 1; Hutchison, et al., WWPUD, E-WW-01, 37. They proposed various remedies.

The PPC agreed with BPA's proposal for adjusting the difference in cost changes in OY 1984 between cost projected and actual cost incurred. Wolverton & O'Meara, PPC, E-PP-01, 6-7; 9. In prefiled testimony, the PPC rejected BPA's proposal for the OY 1985 adjustment in the SSAC for differences in the current 1985 Supply System Budget and the revised 1985 Budget. Wolverton & O'Meara, PPC, E-PP-01, 7. The PPC suggested that the OY 1985 adjustment be limited to the difference in current projected and updated projected rates of interest and inflation. Wolverton & O'Meara, PPC, E-PP-01, 7-8. This would limit the OY 1985 adjustment to account for the elements of future uncertainty used in projecting cost. As the PPC explained during cross-examination, a budget is the product of projections in price and quantity of materials and labor. In their proposed OY 1985 adjustment, the PPC would allow an adjustment based on changes in inflation indices used to develop the price; changes in the amount of labor or material from what was projected would not be included in the adjustment. Wolverton, PPC, TR 6229.

Although the PPC stated under cross-examination that presumably inflation rates would track Supply System expenditures, they agreed that limiting the OY 1985 adjustment to one component of the Supply System cost does not track BPA's obligations and could cause a potential revenue underrecovery. The PPC, under cross-examination, stated that using their proposal, an increase in total Supply System costs could occur concurrently with the SSAC causing a decrease the affected rates. Wolverton, PPC, TR 6229. BPA proposed the SSAC to enable BPA's rates to track changes in Supply System cost, ensuring that BPA is able to meet its financial obligations. BPA, E-BPA-7, 27. The PPC proposal does not provide the same level of assurance that BPA's rates will reflect its obligations.

The PPC also suggested that the SSAC credit the revenue from WNP-2 test energy and that those revenues should be used to offset FBS cost. Since the amount of test energy generated and the price at which it is sold is uncertain at this point, using the SSAC would allow this determination to be made after the fact. Wolverton & O'Meara, PPC, E-PP-01, 8-9. However, revenue from WNP-2 test energy would be difficult to quantify, and there was no evidence submitted that this revenue, however calculated, would be very significant. Any generating plant may produce more or less energy than the amount forecast; test energy would constitute a very small component of the potential variations in the amount of energy generated from Federal resources in general and WNP-2 in particular. Including this component in the adjustment would only track a very small portion of the potential for generation variations.

In prefiled testimony and in their opening brief, APAC supported the SSAC proposed by BPA to adjust rates for reasonable cost changes required to bring WNP-2 into commercial operations. APAC is opposed to using the SSAC as a mechanism to pass on cost changes due to a decision made after the rate hearing to finance expenses through revenues instead of bonds. Cook, APAC, E-PA-2, 65; Opening Brief, APAC, B-PA-01, 96. APAC's concern about a change in financing is basically moot now that BPA is assuming Supply System bonds will not be issued during the test year. Kallio, BPA, E-BPA-21S, 4-5. In supplemental testimony, BPA assumed that conventional financing for the Supply System projects may not be possible in the near future. Until such funds are available, WNP-3 has been placed in a minimum preservation state by the Supply System. The funding required to complete WNP-2 and ramp down and preserve WNP-3 would instead come from revenues. Kallio, BPA, E-BPA-21S, 1-2. BPA modified the SSAC in conjunction with these decisions to exclude any cost increases due to resumed construction on WNP-1 and/or -3. Metcalf, E-BPA-32S, 2-3. In the questioning of BPA witnesses, the point was made that the change BPA proposed in supplemental testimony could lead to a situation where total Supply System costs go up but the SSAC would lead to a reduction in BPA rates. Carr, BPA, TR 5429-5430. This would appear to be a reasonable possibility, if construction debt financing were found. The reduction of WNP-2 costs would lower includable costs, whereas the cost increases associated with constructing WNP-3 would not be includable. Carr, BPA, TR 5426-5430.

Both the PPC and the WWPUD's proposed that a 10 percent limitation be placed on the SSAC. Wolverton & O'Meara, PPC, E-PP-01, 9; Hutchison, et al., WWPUD, E-WW-01, 37; Hutchison, et al., WWPUD, E-WW-02R, 7. APAC supports the concept of a 10 percent limitation on the SSAC. Opening Brief, APAC, B-PA-01, J3.

The PPC proposed that a 10 percent limitation be imposed on the SSAC to ease planning by PF customers. A 10 percent limitation was justified as this "is based on the original purpose of the adjustment clause: to replace additional revenues that BPA felt it could justify putting into rates now. The 'coverage' that BPA felt it could justify was 10 percent." Wolverton & O'Meara, PPC, E-PP-01, 9. The 10 percent "coverage" the PPC referenced is not contained in the record, but was discussed in an open meeting. Wolverton, PPC, TR 6237. During that meeting, the discussion relating to a 10 percent "coverage" was with respect to all of BPA's interest obligations, not just one portion of the revenue requirement. Wolverton, PPC, TR 6276. For the initial proposal, BPA did not adopt a 10 percent "coverage" on its interest expense. This "coverage" was not adopted because BPA felt isolating those portions of the revenue requirement where cost is uncertain and developing mechanisms to limit this uncertainty would be more appropriate. The SSAC is one such mechanism. A 10 percent "coverage" on all interest expenses will not be achieved if a 10 percent limitation is placed on the mechanisms used to limit the uncertain portion of the revenue requirement.

The WWPUD's expressed concern that the SSAC would remove the incentive for BPA to hold down Supply System costs when reviewing and approving the Supply System Budgets. They asserted that limiting the increase in Supply System costs that can be passed on to BPA's customers to 10 percent will retain this incentive. Hutchison, et al., WWPUD's, E-WW-01, 37-38. However, under cross-examination, the WWPUD's agreed to the obvious point that all past Supply System cost increases occurred when BPA had no SSAC. Hutchison, WWPUD, TR 6495-6496. The WWPUD's also argue an unconstrained SSAC would impose hardships on retail utilities that will pass on this increase to their customers. The time between notice of the increase and the effective date is less than two months. This short amount of time would cause difficulties for a retail utility in developing and putting new rates in place quickly enough to avoid undercollection. A 10 percent limit on the SSAC would allow predictability and eliminate the need, on the retail level, for a rate increase only 8 months after the November 1, 1983, rate increase. Hutchison, et al., WWPUD, E-WW-01, 38; Hutchison, et al., WWPUD, E-WW-02R, 27.

BPA acknowledges the difficulties associated with the short time period between notification and implementation of the SSAC. The timing between when

BPA receives the Supply System Budget and cost information, and when BPA must submit the information to its billing department places a constraint on the notification period. BPA will receive the OY 1985 Budget from the Supply System by May 1, 1984, and the BPA billing department requires the rate adjustment information by June 15, 1984, to allow incorporation in the billing process to be effective July 1, 1984. Metcalf, BPA, E-BPA-32, 31. The notification provision reflects the timing limitations while enabling BPA to incorporate the most up-to-date cost information available to present to the affected customers.

While BPA understands the problems its customers have in handling cost increases, BPA also must be concerned about its own ability to recover its costs. The WWPUD's agreed under cross-examination that a 10 percent limitation on the amount of cost that can pass through the SSAC could cause BPA to defer payments to the U.S. Treasury. Saleba, WWPUD, TR 8857. The purpose of the SSAC as included in the initial proposal was to allow rates to track BPA's financial obligations and thus prevent deferral of other obligations. Metcalf, BPA, E-BPA-32, 29; Metcalf, BPA, E-BPA-32S, 2.

Decision

The SSAC has not been limited either to differences caused by changes in projected rates of interest or inflation or by a 10 percent ceiling. Such limitations could defeat the purpose of the SSAC which was to allow Supply System cost increases to be passed on so that BPA could meet its financial obligations. Every effort will be made to hold down Supply System cost during the rate period; however, risking BPA's financial integrity is not necessary or prudent to provide an additional incentive for cost containment.

The limitation contained in BPA's supplemental testimony is reasonable and protects the customers from the additional costs caused by a decision to change the construction status of WNP-1 or WNP-3. However, the language has been clarified so that BPA will not lower rates in a situation where total costs, including those caused by a change in construction status, have increased.

Official notice may be taken that avenues are currently being explored for the purpose of funding construction of the Supply System plants WNP- 1, 2, and 3 through debt financing. As a result, BPA may become liable for payment of construction funds for WNP-1, -2, and -3 loaned to an organization other than the Supply System. The language in the SSAC has been clarified to include the cost to BPA associated with repayment of WNP-1, -2, and -3 construction costs loaned to BPA or another organization, except as limited by the aforementioned limitation.

No provision for test energy sales was included in the SSAC because such sales are likely to be minor and in any event will be indistinguishable from other firm and nonfirm sales. If test energy of WNP-2 were included in the SSAC, it would only be prudent to include all variations in WNP-2 output from the amount forecast.

Issue #2

What procedures should BPA implement to provide public input prior to triggering the SSAC?

Summary of Positions

In the initial proposal, BPA suggested that prior to implementing the SSAC, notice would be provided regarding changes in Supply System cost and the rate adjustments caused by these changes. BPA would then meet with those customers affected by the adjustment to explain the changes. BPA, E-BPA-7, 35; Metcalf, BPA, E-BPA-32, 30. BPA modified the notice provision in supplemental testimony changing the notice date and including a 2-week comment period after the meeting. Metcalf, BPA, E-BPA-32S, 3. Both the PPC and the WWPUD's objected to the absence of a formal comment process to review the adjustment prior to implementation. Wolverton & O'Meara, PPC, E-PP-01, 6-7; Hutchison, et al., WWPUD, E-WW-01, 38-39; Hutchison, et al., WWPUD, E-WW-02R, 28.

Evaluation of Positions

Both the PPC and the WWPUD's recommended that a formal review process should be incorporated in the SSAC. Wolverton & O'Meara, PPC, E-PP-01, 6-7; Hutchison, et al., WWPUD, E-WW-01, 38-39; Hutchison, et al., WWPUD, E-WW-02R, 28. APAC also supported a formal hearing process prior to implementing the adjustment. Opening Brief, APAC, B-PA-01.

In prefiled testimony, the PPC stated that a formal comment process was necessary in light of the potential impact on affected rates caused by triggering the SSAC. Specifically, they expressed concern with that portion of the adjustment regarding the OY 1985 Budget. A budget represents a forecast of future conditions, requiring a certain amount of speculation and projection of future cost. Thus, as part of the comment period, the PPC proposed including a formal review of the new OY 1985 Supply System Budget as part of the proposed adjustment. Wolverton & O'Meara, PPC, E-PP-01, 6-7.

The WWPUD's did not explicitly request review of the Supply System Budget. However, they indicated that the customer hearing on the SSAC should be held prior to BPA's submission of comments and changes on the OY 1985 Supply System Budget. This would allow the incorporation of customer suggestions in BPA's comments to the Supply System. Hutchison, et al., WWPUD, E-WW-01, 39.

In recommending a formal process, the WWPUD's included three specific suggestions:

(1) There should be a record kept including a verbatim transcript;

(2) Bonneville should provide a witness or witnesses to support their SSAC computations and answer questions on the proposed changes in costs; and

(3) Customers or other parties to the proceedings should have an opportunity to examine Bonneville witnesses and provide testimony." Hutchison, et al., WWPUD, E-WW-01, 39; Hutchison, et al., WWPUD, E-WW-02R, 28.

The WWPUD's have stated that allowing for a formal process prior to implementing the SSAC would not cause any delay in adjusting the rates and would increase the credibility of the SSAC. Since the SSAC increases BPA's wholesale rates, the WWPUD's believe the public should be allowed "adequate opportunity" to understand and analyze the support for such a rate increase, and participate in its implementation." Reply Brief, WWPUD, R-WW-01, 34. The WWPUD's believe a single public meeting will not allow for adequate public involvement. Reply Brief, WWPUD, R-WW-01, 34.

In rebuttal testimony, BPA proposed modifications to the notice provision. First, BPA changed the notice date from "prior to July 1, 1984" to "prior to June 15, 1984." Metcalf, BPA, E-BPA-32S, 3. Further, BPA expanded the notice process to include acceptance of written comments for 2 weeks after the meeting. BPA indicated that all written comment received would be evaluated. However, BPA believes the comments should only address the adjustment calculations, not a review of the cost level in the annual Budget. The Supply System Budget is subject to a process allowing review and input by all participants. Metcalf, BPA, E-BPA-32S, 3. BPA does not believe the comment period on the SSAC should provide the parties with yet another opportunity to influence the Budget. Metcalf, BPA, E-BPA-32S, 3.

Decision

The SSAC has been revised to provide for a more formal process, and to incorporate the procedures suggested by the WWPUD's. Prior to implementing the SSAC, BPA will file written testimony and provide witnesses to explain how the adjustment was calculated. Interested parties may also file written testimony. All interested parties will be afforded a reasonable opportunity to cross-examine the testimony of the witnesses. Comments and testimony should be directed towards correctness of the calculation of the adjustment, and should not focus on the appropriateness of the Supply System budgets, because such budgets will themselves have been subjected to an extensive review process.

Implementation of the SSAC does not trigger the requirements of section 7(i) of the Regional Act. Similar to a fuel adjustment clause, the SSAC is a formula rate. The adjustment to be implemented next June is merely the operation of a rate, not a change in rate. See, Public Service Company of New Hampshire, 6 FERC ¶61,299 (1979), and cases cited therein. The hearing conducted on the SSAC adjustment next year is being required as a matter of policy, not out of deference to any legal requirement.

(2) Application

Issue #1

To what rate schedules and rate components should the SSAC apply?

Summary of Positions

BPA proposed that those customer classes allocated FBS costs would be subject to the SSAC, namely the purchasers of PF-83 and CF-83 power. Metcalf, BPA, E-BPA-32, 30. In the initial proposal, BPA suggested that the adjustment would be made to the PF energy charges and the CF rate. BPA, E-BPA-7, 47; Metcalf, BPA, E-BPA-32, 30. APAC and the WWPUD's suggested that the NF-83 Standard rate should also be subject to the SSAC. Cook, APAC, E-PA-08R, 22; Hutchison, et al., WWPUD, E-WW-01, 44-45. APAC, in prefiled testimony, proposed that the adjustment should apply to the PF-83 demand charges as well as the energy charges. Cook, APAC, E-PA-02, 66.

Evaluation of Positions

The WWPUD's recognize that the NF-83 Standard rate is based partly on the cost of FBS resources. Because the Supply System cost is a part of the FBS, the level of the NF-83 Standard rate is affected by the cost of Supply System plants. Hutchison, et al., WWPUD, E-WW-01, 44-45. Absent a split-the-savings rate, APAC agrees that cost changes in the FBS should be reflected in the NF-83 Standard rate. APAC further argues that, applying the SSAC to the PF-83, CF-83, and NF-83 rate schedules will reduce and diversify the financial risk caused by deviations from projected cost. Cook, APAC, E-PA-08R, 21-22.

In the initial proposal, BPA viewed the SSAC as applying to those customer classes allocated FBS cost. Metcalf, BPA, E-BPA-32, 30. Applying the SSAC to the NF-83 Standard rate would complicate the adjustment. First, the Supply System cost component of the NF-83 Standard rate would have to be identified. To trace changes in Supply System cost through the NF-83 standard rate would entail recalculating that rate. Then, presumably, the PF-83 and CF-83 adjusted rates would have to be lowered to reflect that some portion of the changes in Supply System cost would be collected from the NF-83 Standard rate. Metcalf, BPA, TR 7259-7260. To do this BPA would have to compare projected Standard rate sales and revenues with and without the adjustment.

APAC indicated that construction work in progress cost is a fixed cost, and that fixed costs should be recovered through the capacity rate component. For this reason, they proposed applying the adjustment due to changes in Supply System cost to the capacity component of the PF-83 rate. Cook, APAC, E-PA-02, 66; Opening Brief, APAC, B-PA-01, 97. However, the TDLRIC Analysis indicates that the appropriate classification of Supply System costs is 87 percent to energy, 13 percent to capacity. Since most of these costs are energy related and the SSAC could go up and down, it is reasonable to promote ease of administration by applying the SSAC to the energy charge.

Decision

The SSAC has not been included in the NF-83 rate, because that rate schedule has not been allocated Supply System costs. Adjustment clauses are only appropriate for firm power rate schedules. The adjustment in the PF-83 rate applies only to the energy charge to promote ease of administration and because Supply System costs are primarily energy related.

c. Scaling Factor

The test year for this rate case is OY 1985. Rates that are considered to adjustable over the 20 months (November 1983 - June 1985) for which these rates apply were scaled up to a level consistent with the FY 1984 and OY 1985 revenue requirement.

Issue #1

Is it appropriate to use the test year's cost allocations to determine the rates for a 20-month period?

Summary of Positions

In the final proposal, the test year rates were inadquate to recover the FY 1984 revenue requirement to be recovered from adjustable rates from November through June, FY 1984. Rather than scaling the rates over these 8 months to levels higher than the test year rates, BPA opted for a lower scaling factor to apply to all 20 months. The 20-month scaling factor is defined the same as it was in the initial proposal: the revenue requirement from the adjustable rates divided by the revenues projected from the test year rates.

According to the NWU's, determining the FY 1984 rates based on OY 1985 allocation factors inequitably assigns costs for three reasons. First, the exchange loads and resources are based on a 90 percent ramp rather than the 80 percent ramp applicable to OY 1984. Second, the Hanna adjustment is not required in Period A because the Hanna smelter is not scheduled to be operating. Third, the value of reserves credit to the DSI's is overstated because of lower DSI loads in January 1984 than in January 1985. The NWU's advocate making adjustments to the scaling factor process to reflect the different effect that these changes would have on the various rate classes. Wolverton, NWU, E-NW-10, 2-3.

Evaluation of Positions

The use of a test year to determine the cost allocations for a rate period is a standard regulatory practice. That is true even if some of the rate period extends beyond and/or precedes the test year. Performing separate cost determinations and allocations for FY 1984 would add greatly to the administrative burden of the rate case with no significant increase in equity.

Two of the three factors noted in the NWU's testimony that would result in differing cost allocation for the two rate periods have been changed since the intitial proposal. Hanna is now forecast to operate throughout the period, and the DSI load in January 1984 is now closer to the January 1985 load than in the initial proposal.

In any case, adjusting for a limited number of items may not result in a more equitable allocation of cost than a simple scaling, because other factors, which would have a counteracting effect, may be overlooked. For instance, other loads and resources besides the exchange loads and resources are projected to vary from OY 1985 to FY 1984. Either all factors should be adjusted or none should be. The advantage of the scaling approach is that it treats all adjustable rates exactly the same. Schoenbeck, DSI, E-DS-20R, 3-5.

Decision

The cost allocations for the test year have been used to design the rates for the entire rate period. Making adjustments for some items would not necessarily result in greater equity and doing separate allocations for November through June, FY 1984 would be overly burdensome.

Issue #2

Is the Scaling Factor correctly calculated?

Summary of Positions

In the initial proposal, BPA determined the November through June, FY 1984 revenue requirement by starting with the OY 1984 requirement. The OY 1984 revenue requirement uses a 25/75 percent weighting of the FY 1983 and FY 1984 revenue requirements. BPA, E-BPA-7, 80. Subsequently, it was determined that the revenues anticipated from November through June, FY 1984 combined with those from the first 3 months of Period B (last 3 months of FY 1984) would not recover the FY 1984 revenue requirement. This is because the FY 1984 requirement is significantly larger than the FY 1983 requirement, and because the methodology used to calculate the OY 1984 revenue requirement implicitly assumes that revenues minus accounting costs are equal from month to month. Therefore, BPA proposed to calculate the Period A revenue requirement as a residual from the FY 1984 revenue requirement rather than the OY 1984 revenue requirement. Under this methodology it is likely that the scaling factor will be greater than one. Rather than adopt rates for November 1983 through June 1984 that are higher than test year rates, BPA proposed to determine a single set of rates (based on the previously determined test year rates) to apply to the entire 20-month period. Carr & Meyer, BPA, E-BPA-57, 1.

SCE asserted that any adjustment upward should not be applied to Nonfirm Energy rates, because the additional revenues are neeeded to amortize the investment in Federal facilities. Thus, the costs are demand related. Opening Brief, SCE, B-CE-01, 31.

Evaluation of Positions

Since November 1983 through June 1984 is wholly contained within FY 1984, starting the scaling factor calculation with the FY 1984 revenue requirement correctly determines the November through June requirement.

SCE's analysis is incorrect. The revenue increase is associated with all of BPA's costs, not just amortization of the Federal facilities. The last increment of any revenue requirement is used to amortize Federal facilities because that is a low priority in BPA's repayment policy. That is a cash flow consideration and has nothing to do with the identification of cost components. No evidence has been presented that the percentage of the test year revenue requirement identified with Federal investment amortization is less than the percentage of the 20-month revenue requirement associated with that cost component. It is also incorrect that demand costs should not be included in the NF-83 rate (see the NF-83 section for additional details).

Decision

The methodology presented in BPA's supplemental testimony has been used to adjust test year rates to recover the rate period revenue requirement. This methodology has been applied to the NF-83 Standard rate, which is based on BPA's costs. The below-cost Spill and Displacement rates have not been subject to the scaling factor because they are not developed from an analysis of test year costs.

d. Revenue Shortfall Adjustments

In recent years BPA has experienced a serious revenue recovery problem. Several methods (aside from those in BPA's initial proposal) were proposed as a means of avoiding a similar problem during the upcoming rate period.

Issue #1

Should BPA include some sort of adjustment mechanism in its rates to adjust for potential revenue shortfalls?

Summary of Positions

BPA did not propose any specific "adjustment" mechanism for revenue shortfalls in the initial proposal. However, certain measures (such as the proposed billing factors for computed requirements customers and the DSI customer charge) were included in those rate schedules applying primarily to customer classes which have underrun their loads to a significant degree in recent years. BPA, E-BPA-7, 28. Furthermore, BPA proposed the exchange adjustment clause and the Supply System adjustment clause to account for two of the more variable components of BPA's rates. BPA, E-BPA-7, 33-35.

In BPA's rebuttal testimony, BPA's witness suggested that BPA could include a deferral adjustment clause in its rates. If the deferral exceeded the forecast deferral by a predetermined threshold, all rates would be increased to recover that shortfall. Metcalf, BPA, E-BPA-46R, 6-8.

The PGP suggested that an alternative solution to BPA's revenue stability problem, but not a preferred solution, would be for BPA to use a three year rolling average of actual data to derive a $/kW surcharge for each customer to be assessed during the next rate period. Garman, et al., PGP, E-PG-01, 22.

PPC proposed that BPA adopt what could be termed an Unsold Surplus Adjustment Clause, a "mid-course correction" as they called it. Wolverton &

O'Meara, PPC, E-PP-02R, 28-29. Under this approach BPA "would compare actual surplus firm sales to forecast surplus firm sales from October 1983 to May 1984 on June 30, 1984. Any unexpected overruns or underruns would be assigned to the rate classes bearing responsibility for them." Wolverton & O'Meara, PPC, E-PP-02R, 28-29.

The WWPUD's do not believe that it is appropriate to adopt a deferral adjustment clause at this time. They note that BPA has proposed two other adjustment clauses which address BPA's "most volatile revenue streams." Opening Brief, WWPUD, B-WW-01, 77. APAC concurs with the WWPUD's, although APAC blames the revenue recovery problem on BPA's "energy-intensive" rates. Opening Brief, APAC, B-PA-01, 97-99.

PSP&L likewise contended in their opening brief that adoption of a deferral adjustment clause would be inappropriate. Opening Brief, PSP&L, B-PS-01, 10.

Evaluation of Positions

The PGP never fully described their alternative. They treat it as a "revenue stability" proposal, but in fact, PGP's proposal is really an alternative method of allocating the deferral and does not, per se, enhance revenue stability. Metcalf, BPA, E-BPA-46R, 7. It is not clear whether the shortfall would be recovered from all customer classes on a pro rata basis or whether, instead, each customer group would be assigned costs reflecting their share of the revenue shortfall. Furthermore, this alternative presupposes an on-going adjustment which BPA would be required to make for an indefinite period of time.

The PPC's proposal has been discussed under the allocation of the underrecovery from surplus sales.

Under BPA's alternative, all rates would be increased by the same percentage. This proposal is the easiest to implement and recognizes that all customer classes bear some responsibility for the revenue shortfall. However, the WWPUD's, APAC, and PSP&L are correct that this adjustment clause is open-ended and covers some of the same ground as the other two clauses.

Decision

BPA agrees with the WWPUD's and APAC that BPA should not adopt another type of revenue shortfall adjustment. BPA has included a number of measures which are expected to alleviate the revenue shortfall problem, so such a provision should not prove necessary.

4. Shoulder Period Demand Charges

Issue #1

How should BPA incorporate the LRIC shoulder period capacity charge in the rate schedules?

Summary of Positions

Although BPA identified a shoulder capacity period in the TLRIC Analysis, BPA has not incorporated a shoulder period in the rate schedules. Metcalf, BPA, E-BPA-32, 32-34. The WWPUD's noted that it would be premature to adopt a shoulder period capacity charge at this time. Hutchison, et al., WWPUD, E-WW-01, 43. PGP, however, recommended that BPA adopt shoulder period demand charges if BPA believes that the cost differences between the hourly periods will remain from rate period to rate period. Garman, et al., PGP, E-PG-01, 69-71.

Evaluation of Positions

BPA has observed clear differences between capacity costs in shoulder periods and peak periods. Metcalf, BPA, E-BPA-32, 32-34. However, BPA does not currently have the necessary data to forecast coincidental and noncoincidental demand on a daily or hourly basis. In addition, BPA cannot determine, at the present, the extent to which generating utilities would shift loads in response to changes in the peak period. Metcalf, BPA, E-BPA-32, 32-34.

The WWPUD's suggested that reflecting shoulder period capacity costs in rate design is a good idea, but observed that there has not been sufficient analysis to substantiate any of the alternatives. They recommended continuing to study the issue and discussing it prior to the next rate proceeding. Hutchison, et al., WWPUD, E-WW-01, 43. BPA agrees with the WWPUD's analysis of the situation.

Aside from the data problems with regard to implementation of shoulder period demand charges, there are other reasons for not adopting shoulder period demand charges at the present time. The adoption of shoulder capacity periods in BPA's rate design would not be consistent with BPA's goal of rate continuity. Furthermore, shoulder period charges would impose an additional administrative burden on BPA. Metcalf, BPA, E-BPA-32, 32-34.

PGP suggested that rate continuity considerations be superseded by justifiable cost-based reasons which are likely to remain over a reasonable time period. PGP proposed that BPA implement the shoulder rate in order to find the magnitude of inter-period consumption shifts caused by the new rate. PGP favors the charging of separate demand charges for peak and shoulder periods based on maximum usage during those periods. Garman, et al., PGP, E-PG-01, 69-71.

Decision

BPA has not incorporated the TLRIC Analysis based shoulder period capacity charges in the rate schedules due to (1) the lack of information about the effect that such charges will have on BPA's customers; (2) the lack of data required for power billing; and (3) the fact that inclusion of such charges would not be consistent with BPA's goal of rate continuity.

D. Wholesale Power Rate Schedules

In this section issues related to each of BPA's proposed rate schedules are presented. BPA has proposed eleven rate schedules, PF-83, IP-83, IH-83, CF-83, CE-83, NR-83, SP-83, SE-83, NF-83, EB-83, and RP-83. In the initial proposal BPA did not include a schedule for firm energy (FE-83).

1. Priority Firm Power Rate, PF-83

The PF-83 rate is applied to BPA's sales of firm power to public bodies, cooperatives, and Federal agencies as well as to utilities participating in the residential exchange under section 5(c) of the Regional Act. Parties raised six issues with respect to the PF rate. The first issue, addressing classification of costs between demand and energy, is discussed in Chapter II, Classification. The second issue concerns the appropriateness of BPA's proposed billing factors for computed requirements customers. (See section C above.) The third major issue relates to the Low Density Discount (LDD), the fourth issue discusses an irrigation discount, and the fifth issue deals with the question of whether it would be appropriate for BPA to adopt a transformation charge. The final issue relates to separate PF rates for those customers with pre-Regional Act contracts.

a. Low Density Discount

In the initial proposal BPA redrafted the LDD language and added a limitation for the Kilowatthour to Investment (K/I) ratio similar to the limitation on the Consumers per Mile (C/M) ratio. The K/I limitation was calculated by taking the ratio of the C/M limitation (10) to the highest C/M ratio qualifying for the LDD (6) and multiplying that result by the highest qualifying K/I ratio (35). The result, 58.33 was rounded to 60.

Issue #1

Should BPA include a K/I limitation in its LDD eligibility criteria?

Summary of Positions

BPA proposed that a K/I limitation be added to the eligibility criteria for the LDD. BPA believes that such a limitation would be appropriate since there is such a limitation for the other measure of system density, the C/M ratio. BPA, E-BPA-7, Appendix RC, RC-15.

PNGC opposed BPA's proposed limitation, asserting that BPA has not analysed its impacts. Hurless, PNGC, E-PN-02, 5; Opening Brief, PNGC, B-PN-01, i. Salmon River Electric Cooperative would become ineligible for the discount if the proposed limitation were adopted. Hurless, PNGC, E-PN-2, 2.

Evaluation of Positions

BPA proposed this language to "screen out customers which are not typical of utilities with low system densities." Stevens, BPA, E-BPA-31, 15. The

Regional Act language states that the discount is to be applied in order to avoid adverse impacts on retail rates. The K/I ratio is a measure of "adverse impacts of [on] retail rates." Stevens, BPA, TR 3654. A high K/I ratio implies that a utility has many kilowatthours over which investment costs can be spread. As a result, the retail rates of such utilities tend to be lower than the rates of other utilities with similar physical characteristics. This tendency is exemplified by Clatskanie County PUD whose K/I ratio is 239 and whose retail rates are among the lowest of BPA's preference customers. Stevens, BPA, E-BPA-31, 16. In its reply brief PNGC asserts that BPA's retail rate assumptions are erroneous and irrelevant. Reply Brief, PNGC, R-PN-01, 15. PNGC notes that retail rate assumptions are not part of the LDD eligibility criteria, Reply Brief, PNGC, R-PN-01, 15-16, and, by implication, should not be a factor in setting the LDD criteria. However, since the K/I ratio is essentially a proxy for the level of retail rates, Stevens, BPA, TR 3654, and since the purpose of the LDD is to compensate for adverse impacts on retail rates, it is appropriate to consider the relationship of the K/I ratio and retail rates in designing the LDD eligibility criteria.

The PNGC opposed the limitation primarily because it would cause Salmon River Electric Coop. (Salmon River) to lose its discount. This utility will soon have a large industrial customer which would cause the utility to be disqualified under the proposed limitation. They consider this unfair for the following reasons: (1) the industry that would cause Salmon River to become disqualified will be making the investment in the necessary facilities; (2) BPA has not adequately addressed the impacts of its proposal; and (3) the characteristics of the utility have not changed despite the addition of a new customer. Hurless, PNGC, E-PN-02, 4-5.

PNGC argues that if Salmon River were to pay the costs of connecting this new industrial customer, it would still qualify for the LDD. Hurless, PNGC, E-PN-02, 3. Since the industry will pay the associated connection costs, either directly as in this situation or indirectly through its rates, it would seem reasonable to consider the industry's investment when computing the K/I ratio. However, if the industry were to shut down and the utility had made the facility investment, the utility's other ratepayers would have to pay off the investment. By contrast, if the industry were to pay the cost there would be no effect on the other utility ratepayers. Stevens, BPA, TR 3663-3664. In PNGC's reply brief it is stated that BPA should consider the cost of plant provided by consumers in the computation of the K/I ratio, because if there is a plant closure there are 'adverse impacts' to be mitigated by the LDD. Reply Brief, PNGC, R-PN-01, 18. PNGC's assertion ignores the purpose of the LDD. The purpose of the LDD is to offset adverse impacts of BPA's wholesale power rates on retail rates, not adverse impacts of plant closures.

The PNGC's rebuttal testimony discusses the effect that loss of the LDD will have on a utility and its customers. PNGC's witness noted that it would be burdensome for an industry to be required to pay rates that reflect the loss of the LDD to other customers. Hurless, PNGC, E-PN-06, 4; Opening Brief, PNGC, B-PN-01, 5. The PNGC also stated that the existence of the LDD is one of the factors which might attract an industry to a rural area. Hurless, PNGC, E-PN-06, 5; Reply Brief, PNGC, R-PN-01, 18-19. PNGC is correct that if an industry were to cause a utility to lose its LDD, there would be less of an incentive for an industry to locate in the utility's service area. Reply Brief, PNGC, R-PN-01, 19. However, this argument does not mean that it is inappropriate to have any K/I limitation, since whatever measure of system density is used in the LDD formula, the very existence of an LDD provides a disincentive to the utility to become "more dense."

PNGC further argues that the only similarity between Salmon River and Clatskanie PUD is the percentage of power which each sells (or will be selling) to a single industry within their service areas. Reply Brief, PNGC, R-PN-01, 16-17. They note that Salmon River's retail rates are high and will remain so, despite the new industrial customer. Hurless, PNGC, E-PN-06R, 2; Reply Brief, PNGC, R-PN-01, 17. Thus, PNGC has shown that the correlation between the K/I ratio and the level of retail rates is somewhat tenuous.

Power purchased under the NR rate schedule would not be eligible for an LDD. Stevens, BPA, TR 3677. Consequently, contrary to the implications of PNGC's testimony, Hurless, PNGC, E-PN-06, 4, large industrial customers (at least those qualifying as new large single loads) would not be lured to a rural area by the prospect of lower rates as a result of the LDD. However, smaller industrial customers might be encouraged by the LDD.

PNGC appears to oppose any change that would result in a utility which currently receives a discount being disqualified. Opening Brief, PNGC, B-PN-01, 1. In their reply brief, PNGC asserts that "[t]he reference to a single particular discount does not allow an implication that there would be a variety of discounts in the five year period." Reply Brief, PNGC, R-PN-01, 19-20.

In the 1981 Administrator's Record of Decision, it was noted that the BPA "staff will review and determine eligibility of all customers for the LDD at least annually," and the LDD "also will be evaluated regularly to determine whether the discounts should continue to be offered." BPA, Administrator's Record of Decision, 1981 Wholesale Power and Transmission Rate Proposal, IX-9.

These comments reflect the broad discretion provided the Administrator as provided in section 7(d)(1) of the Regional Act. That language states:

> In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers.

Pursuant to both the Administrator's broad discretion in determining the discount and experience gained from operation under the existing discount, the LDD may clearly be amended "as appropriate."

Thus, BPA may, in light of its experience, add a limitation for the K/I ratio similar to the limitation on the C/M ratio to screen out customers which are not typical of utilities with low system densities. Stevens, BPA, E-BPA-31, 15.

Modification of the LDD is not inconsistent with section 8(g) of the General Contract Provisions as alluded to by the PNGC. Jones, PNGC, E-PN-11, 4. PNGC suggests that section 8(g) obligates the Administrator to apply the discount and, after 5 years, "Bonneville and its customers could then consider an amendment to the Power Sales Contract to contractually fix the level and standards for the balance of the term." Jones, PNGC, E-PN-1, 3.

Section 8(g) of the General Contract Provisions provides:

> 8(g) Bonneville shall establish and apply a discount to the rate or rates of utility Customers with low system densities. The level of such discount and the standards for determining which Customers qualify for such discount shall be established pursuant to the rate adjustment process described in this section.
>
> After 5 years of experience in the application of such discount, Bonneville shall review the level and standard of such discount. Such review will occur independent of the rate adjustment process, and at such time Bonneville and the Purchaser may consider an amendment to this contract to fix the level of the discount and the standards for Customer qualification for the balance of the term of this contract, or such other amendments as the parties deem appropriate. Any such amendments shall be by mutual agreement of Bonneville and the Purchaser.

The contractual language clearly indicates the level of the discount, and the standards for determining customer eligibility are to be established in the rate forum. There is no implication that one formula for determination of the LDD be applied over a 5-year period. The 5-year period under various LDD formulas (resulting from each rate adjustment process with attendant refinements) would provide the Administrator at the end of the 5-year period with a broad base of experience in application of the LDD. There would be no purpose of review in the rate proceeding if the LDD formula were not subject to adjustment.

Although PNGC recommended that no limitation be adopted, they stated that, if BPA determined that such a limitation were necessary, a limitation of no less than "100" rather than "60" would be the best. Hurless, PNGC, E-PN-2, 5-6. PNGC asserts that "The K/I Limitation of 60 is Arbitrary, Unreasonable, and Completely Unsupported by Any Evidence." Reply Brief, PNGC, R-PN-01, 17. Contrary to PNGC's assertions, the limitation which BPA proposed is neither arbitrary nor unreasonable, since BPA used an existing mathematical relationship relating to the LDD to calculate the proposed limitation. Stevens, BPA, E-BPA-31, 15. PNGC's calculation, like BPA's, is based on existing mathematical relationships, although PNGC's calculation is premised on the level of Clatskanie's K/I ratio. Hurless, PNGC, DP, 74-75. BPA does not agree with PNGC that it is appropriate to base the design of the limitation on the K/I ratio of a particular utility; rather, the limitation should be established for other reasons.

<u>Decision</u>

PNGC's compromise limitation of 100 for the K/I ratio has been included in the LDD eligibility criteria. The rationale supporting inclusion of a K/I limitation in the LDD is that as the K/I ratio increases, there are more billing units over which the distribution system costs can be spread. However, as PNGC asserts, a utility may have a large retail load without necessarily having low retail rates. This is particularly true for a utility, such as Salmon River, which bases its rates on cost-of-service principles.

BPA does not, however, accept PNGC's reasoning with respect to why "100" is an appropriate limitation. As noted above, it would be inappropriate to base the limitation on PNGC's proposed methodology. Rather, the choice of "100" simply represents a reasonable compromise between the need to have a limitation and the need to encourage growth in rural areas.

Issue #2

Should BPA provide an LDD on PF "exchange" sales?

Summary of Positions

In the initial proposal, BPA assumed that the average system cost for exchanging utilities would reflect the actual cost of power which the exchanging utility would be purchasing from BPA. BPA, E-BPA-7, Attachment 1, 132-134. That is, if the exchanging utility were entitled to an LDD, then the average cost of power purchased from BPA was assumed to be lower than the cost would have been in the absence of the LDD. Thus, BPA assumed that the LDD would apply both to "exchange" sales and to sales used to meet system requirements.

PNGC contended that exchange power should not be eligible for the LDD because the "price for power that includes an LDD is less than what has been determined to be the cost of the generating resources used to serve the utility's load." Johnson, PNGC, E-PN-3, 3. PNGC also noted that the purpose of the LDD is related to the distribution costs of a utility and the determination of the utility's ASC includes only production costs and a limited amount of transmission expenses. Johnson, PNGC, E-PN-3, 2.

Evaluation of the Positions

PNGC appears to making two arguments. First, BPA should not apply the LDD to exchange purchases, and second, if the LDD is so applied, the cost should be borne by those customers whose loads are served by exchange resources.

PNGC maintains that it is inappropriate to grant an LDD on exchange purchases, because the calculation of the utility's ASC does not consider distribution expenses and because the discounted cost of power does not reflect the actual production costs. Johnson, PNGC, E-PN-03, 3. However, the cost of power that the utility actually purchases from BPA is affected by the utility's system density (as measured by the C/M and K/I ratios). The fact that the cost of LDD power may be less than the actual cost of providing service to the customer class is not relevant because an ASC based on an undiscounted PF Rate would not reflect the cost which that utility actually incurs for its power purchases from BPA.

It is also PNGC's contention that "BPA double counts the cost of the LDD for exchanging utilities by first applying the LDD to the total requirements load, and then calculating an additional amount on the amount of the exchange. Reply Brief, PNGC, R-PN-01, 21. PNGC then notes that "[t]he exchanging utility, however, does not receive this 'double counted' amount; it only receives the amount of the LDD over its requirements purchase." Reply Brief, PNGC, R-PN-01, 22. Because the exchange costs are paid primarily by the DSI's, PNGC believes that the DSI's receive the benefits of the LDD as applied to exchange power. Reply Brief, PNGC, R-PN-01, 22-23. This result is, in their view, inappropriate since DSI's are not eligible to receive a LDD. Reply Brief, PNGC, R-PN-01, 23. Consequently, PNGC proposes that BPA allocate the costs of the LDD for the exchange to loads served by exchange resources.

This argument is not valid. There is no justification for the costs associated with the residential exchange to be artificially inflated as PNGC suggests; rather, the exchange costs should reflect the actual costs of PF service from BPA. BPA's position reflects the fact that exchanging utilities which receive an LDD actually pay less for their power than they would in the absence of the LDD. It should be kept in mind that the average wholesale power rate paid by BPA's utility customers varies significantly between customers. Although PNGC is arguing that BPA should not consider the effects of the LDD on the wholesale power rate, they do not suggest that BPA ignore the effects of system load factor, power factor, or other such influences on the average PF rate. Since all the other factors are considered on a class-by-class basis, there is no reason for treating the LDD differently.

Decision

BPA will continue to apply the LDD to all utility purchases of PF power, i.e., both system requirements and exchange power, and continue to allocate the costs to PF purchasers. It is appropriate to apply the LDD to exchange loads, since the exchange costs should reflect actual costs of PF service.

Issue #3

How should BPA distribute the costs of the LDD among its customers?

Summary of Positions

In the initial proposal BPA designed the PF rate to recover the PF revenue requirement, recognizing that some customers receive a discount on their PF purchases. Thus, the PF rate for those customers not receiving a discount is somewhat higher than it would have been in the absence of the LDD. BPA, E-BPA-7, 21.

PNGC contended in its prefiled testimony that BPA should have allocated the LDD costs in the same manner as the costs were allocated for the Hanna Adjustment. Jones, PNGC, E-PN-1, 3.

Evaluation of Positions

PNGC argues that, absent the finding that the discount to Hanna has been beneficial to the region, there is no justification for treating the LDD and the Hanna discounts differently. Opening Brief, PNGC, B-PN-01, 6-7; Reply

Brief, PNGC, R-PN-01, 23. In their reply brief PNGC also notes that BPA has not shown that the discount to Hanna has been beneficial to the region. Reply Brief, PNGC, R-PN-01, 23-24. Because LDD systems are spread throughout the region, BPA could assume a regional benefit from the LDD, Reply Brief, PNGC, R-PN-01, 24, much as BPA assumes a national benefit from service to Hanna.

PNGC maintains that BPA should allocate the cost of the LDD for firm power purchases to all BPA customers (i.e., in the same way as the Hanna discount is allocated) on the grounds that both provisions are contained in section (7) of the Regional Act. The only support PNGC could possibly assert for this proposition is that section 7(d)(1) and 7(d)(2) of the Regional Act begin with the same six words. PNGC has failed to cite a rule of statutory construction wherein statutory provisions including some of the same words are necessarily related.

The weakness of the PNGC argument is evident from the simple fact that the statutory provisions relating to the LDD and the Hanna rate address two completely separate and unrelated issues; section 7(d)(2) addresses establishment of an entire rate for a customer while section 7(d)(1) addresses a discount to rates of many customers. The PNGC suggestion is further weakened in light of the broad discretion provided the Administrator in establishing the LDD and the Industrial Hanna rate. 16 U.S.C. §839e(d).

BPA's allocation of the LDD costs to PF customers is consistent with BPA's allocation of these costs in the past. The beneficiaries of this discount are PF customers since the discount is only applied to PF purchases. By contrast, no single BPA customer class benefits from the Hanna discount. The Hanna discount "will benefit the whole region a(s) well as the rest of the United States by increasing the probability that Hanna will be able to resume operations." BPA, E-BPA-7, 25.

Decision

PNGC's assertion that BPA must demonstrate the value to the region of the Hanna adjustment in order to justify treating the two discounts differently is unfounded. Although the Regional Act provides for both discounts in section 7(d), there is no basis for PNGC's assertion that the costs of the LDD should be spread over all of BPA's customers. The two discounts bear no relation to each other. Because the beneficiaries of the LDD are PF customers, BPA has designed the PF rate to recover the costs assigned to the PF class.

b. Irrigation Discount

Prior to 1974, BPA included a special discount for irrigation loads in its PF rate. In 1974, BPA adopted a seasonally differentiated PF rate which resulted in relatively lower summer and higher winter rates. The irrigation discount was phased out over the 1974-1979 rate period.

Issue #1

Should BPA adopt an irrigation rate in its final proposal?

Summary of Positions

In the initial proposal BPA did not include a special "Irrigation Rate." BPA eliminated its irrigation discount in its 1974 Wholesale Power Rates and has not proposed any discount or special rate since. Hittle, NIU, E-NI-01, 14.

In BPA's rebuttal testimony, BPA presented two alternatives to the Hittle proposal. These alternatives were not introduced as BPA "proposals" but rather as alternatives the Administrator might consider if he were to adopt an irrigation rate in the final proposal. Carr, BPA, E-BPA-51R, 1. One alternative was based on the NIU's proposal that BPA sell irrigators interruptible capacity. Carr, BPA, E-BPA-51R, 4-11. The other, the Offpeak Irrigation Rate Alternative, was a variant of BPA's initial proposal. Carr, BPA, E-BPA-51R, 3-4.

BPA's interruptible capacity alternative treated the irrigation load as "reserves." The irrigators would agree to allow BPA to interrupt their load for forced outage reserves, and BPA would provide a credit equal to that given to the DSI's for their forced outage reserves. Carr, BPA, E-BPA-51R, 4-11. Under the Offpeak Irrigation Rate Alternative BPA would promise to (1) continue the present practice of not charging for capacity during offpeak hours; and (2) retain at least a 9-hour offpeak period. Carr, BPA, E-BPA-51R, 11-12.

The NIU proposed a special rate for irrigators who participate in a program enabling BPA to interrupt their loads in order to meet regional capacity shortages. Hittle, NIU, E-NI-01, 5. Under this proposal, BPA would sell the irrigators firm energy; that is, BPA would not plan to meet the capacity requirements of the irrigators. Hittle, NIU, TR 8594. This concept was endorsed by the Oregon Department of Agriculture and the Washington State Farm Bureau. Kunzman, et al., OD Ag., E-OA-1; Arenholtz, WSFB, E-WS-01.

The WWPUD's opposed a special rate for irrigators stating that not only is agriculture one of many industries hard hit by the recession, but also that "[a] special irrigation rate would result in even greater power cost to Bonneville's other customers including the wood products industry." Hutchison, et al., WWPUD, E-WW-02R, 34; Opening Brief, WWPUD, B-WW-01, 50-51. The WWPUD's also asserted that a special irrigation rate could adversely affect BPA's revenue stability. Hutchison, et al., WWPUD, E-WW-02R, 34.

IPC and UP&L also opposed the granting of a special rate for irrigation customers. They noted that such a rate would result in increased costs to other customers. Reply Brief, IPC/UP&L, R-UP-01, 11. Furthermore, they allege that such a rate would discriminate against irrigators in the service areas of investor-owned utilities. Reply Brief, IPC/UP&L, R-UP-01, 11-12.

Evaluation of Positions

The NIU argues that agriculture is a special and important industry in the Pacific Northwest which is experiencing severe financial stress, aggravated by increasing electric power costs. Kunzman, OD Ag., E-OA-01, 3-4; Dorran, OD Ag., E-OA-6, 28; Opening Brief, NIU, B-NI-01, 5; Reply Brief, NIU, R-NI-01, 1, 5-10. The WWPUD's agree with NIU's position, but note that other industries have also suffered economic hardship. Thus, the WWPUD's contend that it would not be appropriate to institute special rate relief for irrigators. Hutchison, et al., WWPUD, E-WW-02R, 34; Opening Brief, WWPUD, B-WW-01, 50-51.

In their reply brief, the NIU state that the NIU proposal is not a "rate relief" proposal. Reply Brief, NIU, R-NI-01, 1, 3. Rather, the NIU proposal is based on the premise that the irrigation load is off-peak and complementary to BPA's system. Reply Brief, NIU, R-NI-01, 2. The NIU's contend that the basis for their proposal is the nature of the irrigation load, rather than the economic plight of the irrigators. It is noteworthy, however, that the NIU devotes six pages of its reply brief and the vast majority of its prefiled testimony to a discussion of the economic impacts of BPA's proposed rate on the irrigators. NIU contends that "BPA has completely ignored over 100 pages of testimony" which is "uncontroverted and substantial proof in the record that electric power costs. . . contribute to the inability of the region's irrigated agriculture to stay in business." Reply Brief, NIU, R-NI-01, 5-6. According to NIU's own criteria, this testimony is irrelevant since the irrigators do not purport to seek "rate relief." Reply Brief, NIU, R-NI-01, 1.

NIU also asserts that "the goal of enhancing the ability of a major regional industry to stay in business is a proper goal." Reply Brief, NIU, R-NI-01, 2. This is yet another example of NIU's contention which contradicts its own premise that the proposal is "not a rate relief" proposal. The NIU implies that because BPA offers a special rate to Hanna, the irrigators are entitled to a similar benefit. Reply Brief, NIU, R-NI-01, 3. In making this argument the NIU ignores the fact that the rate relief provided to Hanna is statutorily mandated. 16 U.S.C. §839e(d)(1). Congress did not provide for similar treatment of irrigators. However, the NIU is correct in its assertion that a cost-based rate is consistent with the Regional Act. Reply Brief, NIU, R-NI-01, 4. The issue, then, is whether the NIU proposal is indeed cost-based.

It is also true, as stated by the NIU, that BPA did invite distressed industries to submit testimony in support of lower rates. Melton, BPA, E-BPA-10, 17. BPA's statement read as follows: "[i]f a demonstration could be made that, by reducing the rate to a particular customer class below the level resulting from application of the rate directives, BPA total revenues from that customer class would be greater than under the proposed rates, then serious consideration would be given to this situation." Melton, BPA, E-BPA-10, 17. BPA did not state or imply that economic hardship alone would be grounds for BPA's offering a lower rate to a particular customer or consumer class. Rather, all customers were put on notice that BPA's revenues must benefit from implementation of a lower rate in order for such a rate to be considered.

The NIU alleges BPA's irrigation loads would be greater under the NIU proposal than under the BPA proposal. Hittle, NIU, E-NI-01, 12. Thus, they argue their proposal would encourage "widespread use" of electric power. This discounts the ripple effect on all other Priority Firm Power purchasers who would be required to pay a higher rate. Hittle, NIU, E-NI-01, 8-9; Hittle, NIU, DP 119-120; Opening Brief, WWPUD, B-WW-01, 51; Reply Brief, IPC/UP&L,

R-UP-01, 11. Whether the NIU proposal furthers the goal of widespread use depends on the rise and fall of BPA's net loads. IPC and UP&L appropriately contend that decreased use by non-irrigators could exceed increased use by irrigators, thereby counteracting NIU's argument that their proposed rate would result in "widespread use." Reply Brief, IPC/UPC, R-UP-01, 11.

Under the NIU's proposal the irrigators would permit their loads to be interrupted for a few hours during periods of regional capacity shortages in lieu of paying BPA's demand charge during the irrigation season. Hittle, NIU, E-NI-01, 5. The NIU does not, however, describe a satisfactory means for enabling BPA to make use of this capacity, despite their assertions to the contrary in their reply brief. Reply Brief, NIU, R-NI-01, 14-20.

In their reply brief, NIU asserts that the irrigation load would be interruptible. BPA did agree with the NIU that the proposed length of proposed interruptions was appropriate. Reply Brief, NIU, R-NI-01, 14. Yet NIU further asserts that because interruptions would not be likely during the ensuing years due to the capacity surplus, the need for verification would be infrequent. Reply Brief, NIU, R-NI-01, 15. Once again, the NIU has made a valid point, although if the loads will not be interrupted (thereby obviating the need for physical load control devices), it is not clear why BPA should purchase the product.

The fact that BPA may not need the capacity, Hittle, NIU, E-NI-02R, 1; Opening Brief, NIU, B-NI-01, 7, does not mean that BPA should not have ready access to that capacity if BPA is paying for it. The NIU stated that different irrigators would require different periods of notice in order to shut off their pumps. Hittle, NIU, E-NI-01, 6-7; Hittle, NIU, E-NI-02R, 14. In exchange for these interruption rights the NIU proposed that BPA excuse qualifying irrigation load from the demand charge during the irrigation season. Hittle, NIU, E-NI-01, 5.

The NIU is proposing that BPA sell irrigation utilities firm energy up to the amount of their irrigation load. However, the NIU does not consider the irrigation load to be a capacity "reserve;" rather, they are proposing that BPA interrupt the capacity load only if appropriate notice can be supplied. Hittle, NIU, E-NI-02R, 14. Thus, it would seem that BPA must in fact plan on serving that irrigation load since it has no guarantee that it will not in fact have to serve it during an actual capacity shortage. Carr, BPA, E-BPA-51R, 5; Opening Brief, WWPUD's, B-WW-01, 54.

The NIU's contention that irrigators would not receive the special rate if they could not be interrupted, Reply Brief, NIU, R-NI-01, 16, is unfounded. There is nothing in the NIU proposal which would prevent an irrigator from receiving rate relief and continuing to purchase PF power even during a supposed restriction. Furthermore, even the NIU concurs that an "honor system" such as they propose is not likely to be 100 percent successful. Hittle, NIU, TR 8597. Thus, their proposal provides no guarantee that the irrigator has actually turned his pumps off during an "interruption."

The monitoring system proposed by the NIU to verify compliance, Hittle, NIU, E-NI-02R, 12; Opening Brief, NIU, B-NI-01, 8, is inadequate. Imposition of an after-the-fact penalty is not sufficient. Such a post-hoc measure would not help BPA manage a capacity problem, though it may raise the compliance rate.

Thus, in order for BPA to rely on its interruption rights, BPA must have control over the irrigation facilities subject to interruption. This control is particularly important in order for BPA to respond appropriately to a sudden or unanticipated loss of capacity. If BPA does not physically control the interruption, there is no way to verify whether the irrigator has actually complied with the order to shut off his system. Carr, BPA, E-BPA-51R, 5.

The NIU asserts that BPA should be able to provide advance notice of impending capacity shortages. Hittle, NIU, E-NI-02R, 14. Certainly, BPA could keep irrigators and utilities apprised of reservoir refill and snowpack conditions taken together provide a good indicator of forthcoming streamflow conditions. However, shortages for which there would be little or no forewarning are far more likely to occur. In those cases, BPA would be unable to provide anywhere near the requested 48 hours notice since the need to use forced outage reserves might well be almost instantaneous in nature. Carr, BPA, E-BPA-51R, 4; Carr, BPA, TR 7986. NIU is correct that BPA does not "expect" to need forced outage reserves in the near term. Reply Brief, NIU, R-NI-01, 17. However, the fact that BPA does not "expect" to need the reserves, does not negate the fact that BPA might, nonetheless, need them. If they are needed and if BPA is paying for them, BPA should have complete and easy access to them.

Throughout cross-examination of BPA, the WWPUD's expressed concern about whether BPA would be adhering to "sound business principles" if it were to purchase reserves or interruption rights from the irrigators. Carr, BPA, TR 7982-7983. When questioned as to the need for additional capacity reserves, BPA noted that while additional reserves could be used in some months, they would not be needed in all months in which they would be available. Carr, BPA, TR 7982-7983; BPA, E-BPA-3, Vol. II, 219.

There are serious practical problems associated with implementing an interruptibility provision for the irrigation customers. BPA noted that approximately 30,000 irrigators would have to be interrupted in order to achieve a 500 megawatt reduction in load. Carr, BPA, TR 8003-8004. NIU is correct that BPA would not bear the notification burden; BPA would only notify the utilities. Reply Brief, NIU, R-NI-01, 18. However, regardless of who notifies the irrigators, notifying 30,000 individuals of an impending restriction is a logistical problem.

The NIU consistently drew a distinction between their proposal and the BPA alternative. The NIU witness stressed that under their proposal irrigators would be providing BPA with interruption rights, whereas under BPA's alternative the irrigators would provide reserves. Hittle, NIU, TR 8595-8596; Hittle, NIU, TR 8603-8604. NIU asserted that the real basis for their proposal is not the proposed interruptibility rights, but rather the fact that irrigation load is basically a summer load. Hittle, NIU, TR 8603-8604; Opening Brief, NIU, B-NI-01, 1. The WWPUD's note that "[t]aken to its logical extreme, this approach would charge all of Bonneville's capacity costs to the annual peak day, and provide capacity as a free good the other 364 days of the year. Such an approach is not good logic nor good business." Opening Brief, WWPUD, B-WW-01, 52.

Although the NIU assert that the irrigation load is a summer load, they do not suggest that BPA generalize their proposal to include giving rate relief to other seasonal loads such as air conditioning loads. The NIU is correct in their assertion that the WWPUD's provided no evidence to demonstrate that there are other off-peak loads which would justify a rate design adjustment. Reply Brief, NIU, R-NI-01, 3. However, the NIU argument misses the point. It is not necessary to identify the purpose for electricity consumption in order to reflect cost differences by season. Rates can be seasonally differentiated, as BPA's are.

Although the NIU proposal "provides that the off-peak rate would be available during the irrigation season," NIU also asserted that "the proposed rate would be applicable for irrigation loads at any time." Opening Brief, NIU, B-NI-01, 11. While winter irrigation loads may be small, it would be entirely inappropriate for BPA not to charge for demand on the day of the system peak. The NIU asserts that the irrigation load would be off on the day of the system peak. Hittle, NIU, E-NI-02R, 11; Reply Brief, NIU, R-NI-01, 23. BPA agrees with the NIU that it is certainly likely that the loads would be off, but there is no guarantee. It would be possible for the system peak to occur in November which is, according to the NIU, appropriately considered an irrigation month. Hittle, NIU, DP 138.

Furthermore, while the irrigation load may not contribute significantly to BPA's load on its peak day, the load is a contributor to BPA's summer peak load. Hittle, NIU, DP 111. BPA's summer load is only 8.3 percent less than the winter load. Hutchison, et al., E-WW-02R, 36. Furthermore, the PONM analysis shows that the month of April, the first heavy irrigation month in the year, has the greatest PONM of all 12 months. Opening Brief, WWPUD, B-WW-01, 53. The NIU suggests continuing to use the current PONM methodology and note that changes can be made to reflect new conditions. Hittle, NIU, E-NI-02R, 5-6; Opening Brief, NIU, B-NI-01, 13. BPA agrees with the WWPUD's that the irrigation loads do contribute to BPA's summer peak and are significant in the month when the PONM is greatest.

In their reply brief, the NIU takes exception to BPA's suggestion that April is the first month of substantial irrigation load. Reply Brief, NIU, R-NI-01, 20. However, while it is true that loads in the period May through September are even larger than the April load, according to NIU's own data April loads are more than eight times larger than March loads. Hittle, NIU, E-NI-01, 22. Furthermore, the April load is not inconsequential; it is approximately equal to the load of an aluminum-producing DSI. Finally, the NIU asserts that the irrigation season really begins in early March and continues through November. Hittle, NIU, DP 138. Thus, the NIU considers the April load sufficiently large to warrant special rate treatment.

The NIU also takes exception to the WWPUD's quotation of 8.3 percent as the difference between the summer and winter load. Reply Brief, NIU, R-NI-01, 21-22. NIU is correct that the difference between summer and winter loads is increasing, but fails to take into account the fact that BPA's rates reflect those differences.

Finally, it should be noted that the irrigators have already received substantial benefits from BPA's recent wholesale power rate designs. Carr, BPA, E-BPA-51R, 2-3; Hittle, NIU, E-NI-1, 16. Seasonal differentiation has been beneficial, Carr, BPA, TR 7981-7982; Hittle, NIU, TR 8589-8591, so too the LDD. Metcalf, BPA, TR 5438-5439. In addition, BPA modified its seasonal differentiation in the initial proposal, resulting in even greater benefits to the irrigators. This modification involved moving the month of May from the winter to the summer capacity season and spreading the energy costs associated with the month of May over the remaining 11 months, resulting in lower summer energy rates. BPA, E-BPA-7, 38; Carr, BPA, E-BPA-51R, 2-3. However, the NIU argues that the benefits from diurnal differentiation, seasonal differentiation, and/or the LDD are all mutually exclusive and are not a substitute for each other or the NIU's proposal. Opening Brief, NIU, B-NI-01, 16-17. However, the seasonal differentiation is a cost based substitute for the NIU's proposal. It reflects the lower cost to serve all loads during the summer, not just the loads of one particular group.

A somewhat different argument advanced by NIU is that there is legal and historical precedent for a special irrigation rate. NIU, B-NI-01, 2. While BPA has had an irrigation discount in the past, the discount was phased out over a 5 year period, 1974 through 1979. Hittle, NIU, E-NI-01, 14. The most recent legislation affecting BPA on a wholesale basis is the Regional Act. Among other things, this Act addresses many rate-making issues. The Regional Act does not explicitly provide for BPA to offer rate relief to irrigators, although it does indicate rate relief for low density utility systems and the Hanna Nickel Smelting Company. 16 U.S.C. §839e(d)(1)(2). The Act consistently emphasizes the importance of equity in the distribution of Federal power benefits. For instance, section 5(b)(6) provides that restriction rights in contracts with public bodies and cooperatives must be exercised uniformly. BPA cannot restrict any customer until total customer firm loads exceed firm capability and the contracts with these customers must contain a formula for determining entitlements during any restriction period on a uniform basis. Still more compelling, section 7(g) of the Regional Act requires the Administrator to:

> equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including but not limited to, conservation, fish and wildlife measures, . . . operating services, and the sale of or inability to sell excess power.

Where Congress intended special treatment for any particular 'subset' of customers in a rate class, it provided clear direction to that effect in Section 7 of the Regional Act. Section 7(d)(1) provides the Administrator with discretion to establish discounts for customers with low system densities. Section 7(d)(2) gives the Administrator discretion to set a special rate for Hanna Nickel under particular circumstances.

During development of the Regional Act, much attention was paid to irrigated agriculture, generally in the context of curing the rate inequity felt by irrigators not served by preference customers and who were, therefore, paying higher rates than their competitors. Early in the process, it was proposed that use of up to 100 horsepower for irrigation/pumping be defined as being within the class of residential uses and hence qualified for PF power under the exchange. Over time, this ceiling was raised first to 300 horsepower, and, at the urging of Senator McClure, to 400 horsepower. The discussion of "residential use" definition in H. Report 96-976, Pt. 1, shows that Congress considered the rate treatment which irrigated agriculture ought to receive. " This . . . horsepower limit is likely to embrace all "family farms" in the region and some large corporate farms. Large corporate farms that do not qualify would be treated the same as commercial and industrial customers of IOU" (Pg. 52, emphasis added).

All of the above makes it clear that Congress had full opportunity to direct any special rate consideration it wished for irrigated agriculture. The Act provided explicitly for special rate treatment for Hanna and for low density customers as well as for the exchange benefit to irrigators (up to 400 horsepower) served by private utilities. Congress did not mandate that a special irrigation rate be established at the expense of other BPA customers purchasing under the PF schedule.

This is not to imply, however, that the Administrator is restricted to rate designs specifically enumerated by Congress. Section 7(a)(1) of the Regional Act provides:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. Such rates shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act, 16 U.S.C. §838, and the provisions of this Act (emphasis added).

Section 7(e) of the Regional Act provides:

> Nothing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

The legislative history of section 7(e) indicates that it is intended to be permissive:

> Section 7(e) clarifies that BPA may continue, as it does under existing law, to charge uniform rates for the sale of electric peaking capacity. This subsection also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money. For example, time-or-day rates, seasonal

rates, rate structures designed to give BPA customers particular price signals, and other rate forms would be permissible. House Interior Report at 53 (emphasis added).

Thus, when read together, both sections require the Administrator to recover through his own rate structure, the costs associated with acquistions and other costs and expenses incurred by the Administrator under the Regional Act, in accordance with sound business principles. Sections 7(a) and 7(e) leave to the Administrator the rate forms to be used to recover his costs.

As previously stated, whether the NIU proposal would comport with the goal of widespread use and sound business principles depends on whether BPA's net loads would rise or fall. IPC and UP&L correctly indicate there has been no analyses of the net change in either consumption or revenues from shifting costs from irrigators to non-irrigators. Reply Brief, ICP/UPC, R-UP-01, 11. There is insufficient evidence to prove that the increase in BPA revenues from the additional irrigation load would more than offset the decrease in revenues from the loss of other PF loads. It would not be prudent business practice to institute such a proposal without an assurance that BPA's overall revenue would increase.

In their reply brief, IPC and UP&L point out that because the exchange is an accounting transaction, it would be impossible for BPA to interrupt irrigation loads of investor-owned utilities (IOU's). Consequently, irrigation customers of the IOU's would not be able to take advantage of the NIU proposal. Reply Brief, IPC/UP&L, R-UP-01, 11-12. BPA agrees with IPC and UP&L that they have identified an additional problem with the NIU proposal.

This additional problem results in an unavoidable and inequitable situation for irrigation loads of investor-owned utilities. This inequitable result is in direct conflict with section 9(g) of the Regional Act which mandates an equitable allocation of power rates in accordance with generally accepted ratemaking principles and the provisions of the Act. 16 U.S.C. §839f(g).

Decision

It is not appropriate for BPA to single out the irrigators for special rate relief. Such relief is not mandated in the Regional Act nor can the irrigation proposal provide tangible "system benefits." While the NIU asserts that no other customer proposal is held to the same standard (i.e., the standard of providing tangible system benefits), Reply Brief, NIU, R-NI-01, 14, it is also true that no other customer is seeking a lower rate based on the nature of their load. BPA would hold all other customers seeking similar reductions to the same standard.

It is true that irrigators, as a consumer class, do exhibit characteristics that are favorable to the BPA system. However, BPA's rates already reflect the lower system costs associated with the summer and the Water Budget periods. In addition, it is unclear whether an irrigation rate would be consistent either with BPA's conservation efforts or with "sound business principles." The load/resource balance demonstrates that in the test year BPA does not require the reserves that the irrigators would provide. BPA, E-BPA-3, Vol. II, 219; Opening Brief, WWPUD, B-WW-01, 55. While the NIU have not suggested that their proposal provides BPA with reserves, the fact remains that an interruptibility right, as they propose is a reserve. This proposed interruptibility right, which would provide for substantial advance notice, is merely an example of a low quality reserve. It has been argued that BPA currently pays for reserves provided by the DSI's even in years when they are not needed. Wolverton & O'Meara, PPC, E-PP-01, 29-30. However, the two situations are not comparable since BPA has already purchased the DSI reserves. Thus, the DSI reserves are a "sunk cost" while, in contrast, the irrigation reserves would be a new purchase.

In summary, there is no basis for implementing a special irrigation rate at this time.

c. Transformation Charge

In the 1974 wholesale power rates, BPA assessed a two-step transformation charge on PF customers receiving service from BPA at voltages of less than 150 kilovolts. The charge was abolished in the 1979 wholesale power rates.

Issue #1

Should BPA adopt a transformation charge in its PF rate?

Summary of Positions

BPA's initial proposal did not include a transformation charge in the PF rate. BPA, E-BPA-7, 36-38. The PGP advocated that BPA reinstate the transformation charge because customers who receive BPA furnished distribution facilities should pay for them, imposition of the transformation charge would maintain BPA's stated goal of rate continuity, and transformation charges are justified based on cost of service considerations. Garman, et al., PGP, E-PG-01, 65-67.

Evaluation of Positions

As originally noted in the 1979 Record of Decision (and quoted in BPA, E-BPA-7, Appendix B, B-8), "BPA found that there is very little correlation between higher cost and lower voltage. Location, size, reserve capacity, chronological date of initial service, and voltage all have some impact on costs. It would be inequitable to isolate and develop a separate charge for only one of these cost indicators." BPA also stated in its initial proposal that the issue regarding provision of customer service facilities is best handled through a uniform customer service policy. Melton & Frick, BPA, E-BPA-35, 4. In addition, it was demonstrated that a transformation charge would "eliminate many of the economic benefits of the LDD, ETCA, and Residential Exchange. BPA, E-BPA-7, Appendix B, B-16, B-17.

PGP's assertion that reinstating the transformation charge is necessary in order to maintain rate continuity does not reflect the fact that BPA has not assessed a transformation charge since December 20, 1979. BPA has recognized that some utilities made investments in facilities as a result of the charge and has taken mitigation measures, where such mitigation was warranted. BPA, E-BPA-7, Appendix B, B-13. Thus, at this time "rate continuity" would dictate that BPA not assess a separate charge for transformation.

PGP's contention that cost of service principles would dictate institution of a transformation charge is also incorrect. The Administrator has elected to apply the postage stamp concept to his wholesale power rates. BPA, E-BPA-7, Appendix B, B-9. Under the postage stamp principle, costs are not separated to account for different cost causation factors. If the PGP position were taken to a logical conclusion, it would make sense for BPA to account separately for facilities by year of construction, type of equipment, physical location, size, etc. A separate accounting such as this would be highly impractical.

During cross-examination by PNGC, BPA reiterated its contention that adopting appropriate language in the customer service policy regarding construction of new and modification of existing distribution substations would probably obviate the need for a transformation charge. Frick, BPA, TR 3613. In addition, BPA noted that a customer taking high voltage deliveries could possibly receive ETCA benefits while being exempt from a transformation charge. Frick, BPA, TR 3616.

The PGP agreed with PNGC's counsel that a utility that "plans, constructs, and operates its system independent of Bonneville may derive benefits from that independence." Garman, PGP, TR 6514-6515. The fact that BPA does not always provide transformation facilities for each of its customers may be a matter of customer choice, rather than BPA policy. Garman, PGP, TR 6514-6515. Thus, instituting a transformation charge may simply provide those customers taking 230 kilovolt service with an additional benefit and may represent an unnecessary incentive to construct their own substations.

Decision

Cost of service principles do not require a utility to account separately for costs incurred as a result of every possible cause. BPA has determined that there are many causal factors affecting the cost of power deliveries to its customers. In addition, rate continuity would dictate that BPA not adopt a transformation charge. Consequently, BPA will continue to offer wholesale power rates using a rolled-in transmission system.

d. Priority Firm Power Rate for Customers with Pre-Act Contracts

Issue #1

Should BPA have a separate rate for customers with pre-Act power sales contracts?

Summary of Positions

In the initial proposal BPA proposed that customers with pre-Act contracts pay the same rates for power as customers with Regional Act contracts. The cities of Canby and Cascade Locks in Oregon, Centralia, Washington, and Mason County PUD No. 3, and Pacific County PUD No. 2 in Washington argue that because they are purchasing power from BPA under pre-Act contracts and because they are excluded from participating in certain Regional Act programs, it is inequitable for BPA to charge them for the costs of these Regional Act programs. Thompson, Non Gen, E-NG-1, 7-8; Opening Brief, Non Gen, B-NG-01, 10-14.

Evaluation of Positions

In prefiled testimony the Non Gen customers claimed that they are being excluded or may be excluded from (1) the long-term conservation contract; (2) the Institutional Building Conservation Program; and (3) the billing credits program. Thompson, Non Gen, E-NG-01, 2-3; Opening Brief, Non Gen, B-NG-01, 3-5.

The Non Gen customers also stated that they are precluded from obtaining the benefits of BPA's resource acquisition (including residential exchange) program because they may be restricted from obtaining all of their power requirements from BPA under the allocations process instituted by the Notice of Insufficiency under their pre-Act contracts. Thompson, Non Gen, E-NG-01, 4-6; Opening Brief, Non Gen, B-NG-01, 5-6.

Thus, they contend that if the Administrator continues to exclude customers with pre-Act contracts from Regional Act programs and also continues to impose an allocation under the Notice of Insufficiency (which limits his obligation to serve their entire requirements), the Administrator must develop two sets of rates for power sales: one for sales to customers with Regional Act contracts and another for sales to customers with pre-Act contracts. Thompson, Non Gen, E-NG-01, 7-8; Reply Brief, Non Gen, R-NG-01, 5.

However, two events have occurred since these customers took this position in their prefiled testimony. First, on June 28, 1983, BPA offered its long-term conservation contract to each of them. The Administrator stated in his offer to these customers that the contracts, if accepted, would terminate on June 30, 1985, unless terminated earlier. In their reply brief the Non Gen customers argue that BPA has not made the Non Gen argument "moot" by virtue of this offer. Reply Brief, Non Gen, R-NG-01, 1. The Non Gen customers note that their conservation contracts have a term five and a half years shorter than the term of the conservation contracts offered to BPA's other utility customers. Reply Brief, Non Gen, R-NG-01, 2. Thus, they argue that they are being asked to pay a full share of the costs of the programs implemented pursuant to these contracts while being offered only limited participation. Reply Brief, Non Gen, R-NG-01, 2. This argument is not valid. The Non Gen customers are only bearing the conservation costs associated with this rate period; consequently, they are not harmed in this rate period by having their conservation contracts terminate earlier than the contracts of BPA's customers with Regional Act contracts.

The second event which nullifies the Non Gen argument has to do with the fact that BPA has established the allocation of energy under the Notice of Insufficiency issued under pre-Act contracts. In a letter dated June 30, 1983, the Administrator established the hydro, thermal, and "additional" allocation for each of these customers for the 1983-84 operating year. The additional allocation is based upon BPA's projected surplus of firm energy during the 1983-84 operating year. It was established to serve any part of the customers' net requirements which is not served by the hydro and thermal allocations. The letter states that the additional allocation will be offered in future years if BPA determines that a projected surplus of firm energy is available to make the allocation. For the 1983-84 operating year, BPA will serve the entire net energy and capacity requirements of these customers at the PF-83 rate.

Therefore, the two major bases for the customers' objection to paying the proposed PF-83 rate, Thompson, Non Gen, DP 65-66, have been eliminated. The Non Gen customers will be able to participate in the long-term conservation contract for the entire rate period. They will also have the assurance that their entire net requirements will be served in the next operating year and that BPA will continue to provide that service if sufficient firm surplus continues to be available.

The decision to exclude the service areas of utilities with pre-Act contracts from the Institutional Buildings Program (IBP) reflected the fact that customers with pre-Act contracts can more easily terminate their power sales contract than can customers with Regional Act contracts. That decision was not challenged when the IBP contracts were offered. The Billing Credits policy exclusion of these utilities is based upon a statutory interpretation of the Regional Act. However, the important point to be made with regard to the issue of paying for these programs is that all BPA customers benefit from the programs, regardless of whether projects are, or can be, funded in their particular service areas. Thompson, Non Gen, DP 65-66. BPA's conservation and billing credits programs provide for a cheaper and more assured power supply in the future. The programs also provide greater assurance of BPA's being able to continue to supply the entire needs of these utilities prior to the time their contracts expire.

There is no statutory support for the assertion that BPA must establish two sets of rates, one reflecting costs without the Regional Act or without certain portions of the Regional Act costs, and the other including all costs the Administrator has incurred since passage of the Regional Act. Section 7 of the Regional Act, sections 9 and 10 of the Federal Columbia River Transmission System Act, and section 5 of the Flood Control Act of 1944 all govern establishment of BPA's rates. Section 7(a)(1) of the Regional Act provides:

> Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power system (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. 16 U.S.C. §839e(a)(1).

Section 7(a)(1) of the Regional Act clearly controls all rates established or revised by the Administrator after the enactment of the Regional Act, regardless of the contracts to which they may apply.

The Regional Act's rate directive governing BPA's rates to public agency customers further clarifies that Congress intended no distinction between rates under old contracts and rates under new contracts. Section 7(b)(1) of the Regional Act provides:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c). Such rate or rates shall recover the cost of that portion of the Federal base system resources needed to supply such loads until such sales exceed Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads first from the electric power acquired by the Administrator under section 5(c) and then from other resources. 16 U.S.C. §839e(b)(1).

Section 7(b)(1) clearly provides that the Administrator must establish rates of general application for preference customer sales. Furthermore, those rates must recover all costs of power needed to supply preference customer loads, including exchange resources and new resources, if those additional resources are needed to meet preference customer loads. "Federal base system resources" is a term specifically defined in the Regional Act. 16. U.S.C. §839e(a)(10). No language in 7(b)(1) requires, or even allows, the Administrator to develop a separate lower rate for sales to preference customers under pre-Regional Act contracts.

Decision

The concerns of these customers have, for the most part, been satisfied. In addition, there is no statutory authority for BPA to establish separate rates for customers with pre-Act contracts. Therefore, BPA is establishing a single PF rate for all its PF customers.

2. Industrial Firm Power Rate, IP-83

The IP-83 rate is available to BPA's existing direct-service industries (DSI's). The rate includes a credit for the system reserves provided by those industries.

a. Customer Charge

BPA's proposed IP-83 rate included a customer charge in addition to the demand charge and energy charge.

Issue #1

Should the IP-83 rate include a customer charge?

Summary of Positions

In the initial proposal, BPA included a customer charge for purchasers under the IP-83 rate to enhance BPA's revenue stability. BPA, E-BPA-7, 39. The DSI's opposed any customer charge unless it is agreed to as part of an alternative rate package. Mizer & Blevins, DSI, E-DS-15, 1-2. The NWU's, in their prefiled testimony, supported a customer charge in order to lower the variable component of the DSI rate. Wolverton, NWU, E-NW-02, 5; McCullough & Wolverton, NWU, E-NW-24R, 11.

Evaluation of Positions

BPA proposed a customer charge for the IP-83 rate in order to enhance revenue stability from that rate class. Improvement in revenue stability is needed because of the fixed high cost resources used to serve the load, the relative homogeniety of the load, and the melding of costs assigned to the first quartile with those of the lower three quartiles. Metcalf, BPA, E-BPA-32, 39. Evidence was presented that DSI load underruns have been a major contributor to BPA revenue underrecovery. Metcalf, BPA, E-BPA-46R, Attachment 1, 3. The DSI's themselves also presented testimony from many witnesses that many of aluminum plants in the Northwest have become swing plants whose operation can be expected to vary widely. Opening Brief, DSI, B-DS-01, 2-6.

The DSI's have argued that BPA is contractually impaired from implementing a customer charge in the IP-83 rate. Although they never seriously question BPA's need to maintain stable revenues in situations where customer loads fall below forecast levels, the DSI's would limit BPA to remedial rate designs expressly mentioned in their power sales contracts. This argument is premised on the so-called "Sierra-Mobile" contract cases. FPC v. Sierra-Pacific Power Co., 350 U.S. 348 (1956), and United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956). However, the DSI's have misinterpreted the Sierra-Mobile doctrine and their contracts. The IP-83 customer charge is lawful.

The Sierra-Mobile doctrine has never been judicially applied to the BPA ratemaking process, and BPA does not acknowledge the applicability of that doctrine in this decision. (Cases cited by the DSI's in their prehearing brief, at 51-54, concern rates governed by the Federal Power Act and the Natural Gas Act, not the Regional Act.) Moreover, even if it were assumed that the doctrine did apply, the DSI's have misread the law. The DSI's argue that the Sierra-Mobile doctrine prohibits BPA from implementing any rate design change not expressly mentioned in their contracts. To do so, they claim, would be a unilateral change in those contracts. Prehearing Brief, DSI, 52-53. However, the doctrine is far less restrictive: "[The utility,] like the seller of an unregulated commodity, has the right in the first instance to change its rates as it will, unless it has undertaken by contract not to do so." United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div., 358 U.S. 103, 113 (1958). To prevail, the DSI's must establish that their contracts prohibit implementation of a customer charge.

The DSI contracts do not specify rate levels or rate design features. Instead, they merely incorporate by reference the currently effective industrial class rate established by the Administrator under the Regional Act. For example, section 8(a) of their contracts requires the Administrator to "establish, periodically review and _revise_ rates for the sale and disposition of electric power, capacity or energy sold pursuant to the terms of this contract." Section 8(b) establishes the steps to be followed in proposing new rate schedules. Sections 4(c) and 8(c) require the purchaser to may BPA "_at the rate specified in any rate schedule available_ . . . for service of the class, quality and type provided for in this contract, _and in accordance with the terms thereof_ . . . (emphasis added). Section 8(e) states that the "wholesale power rates . . . all be developed _consistent with the provisions of section 7 of P.L. 96-501_." Similar language was contained in the contract at issue in _United Gas Pipe Line Co_. v. _Memphis Light, Gas and Water Div_., 358 U.S. at 105. The Court found no Sierra-Mobile barrier to any change in rate.

These contractual references make clear that the DSI contracts are not rate-setting documents. Instead, they defer to the Administrator's authority under the Regional Act to establish rates necessary to recover BPA's revenue requirement. The Administrator has considerable discretion in setting rates, as long as the procedural requirements of section 7(i) are satisfied. Such discretion extends to the establishment of a customer charge, which clearly is a rate for the sale of electricity. _See_, _e.g._, _Mobile Oil Corp_. v. _TVA_, 387 F. Supp. 498 (N.D. Ala. 1974).

One possible Sierra-Mobile argument remains. In the 1982 BPA rate proceeding, the DSI's argued that the curtailment charge included in section 9 of their power sales contract was the only revenue stability feature lawfully includable in their rate. They apparently regard any additional rate design element as necessarily inconsistent. However, the language of the contract does not support any such narrow interpretation. Moreover, the customer charge and the curtailment charge are totally compatible revenue stabilizing elements of the IP-83 rate. That rate is comprised of three discrete components: a demand charge, an energy charge, and a customer charge. The customer charge, which is designed to recover approximately 40 percent of BPA's revenue requirement allocated to the industrial class, operates regardless of the level of DSI loads. The curtailment charge, which recovers fractional amounts of the IP-83 demand charge, operates only when the DSI's curtail their demands below the first quartile. The two charges recover different portions of BPA's industrial class revenue requirement. There is no overlap or conflict between the two charges that might support any DSI allegation that the contractually specified curtailment charge precludes imposition of a customer charge.

The terms of the DSI's power sales contracts fail to indicate any intent of the parties to restrict the ratemaking flexibility of the Administrator. Rather, the contracts defer to the ratemaking process for the resolution of rate matters. There is no basis for the DSI's assertion that the Administrator is prohibited by the Contract from establishing a customer charge.

The DSI's also criticized the customer charge because of the operational and economic problems of nonaluminum DSI's. Mizer & Blevins, DSI, E-DS-15, 1-2. Pennwalt testified that its business inevitably has variations in levels of operating that cannot be predicted with certainty. Locke, DSI, E-DS-6, 3. It is ironic that the DSI's, who argue so strenuously that their high load factor is beneficial to the region, also argue that they should be able to vary their production from month to month and year to year without paying for the costs associated with those load variations. The DSI witness admitted that customers whose purchases vary are more expensive to serve than customers whose load is steady from month to month and year to year, and that it is appropriate for the rate design to reflect that cost relationship. Mizer, DSI, TR 6821. The DSI's also argue that their alternative rate design would reflect that cost relationship and provide the revenue stability BPA desires. Mizer, DSI, TR 6821. However, there is no assurance that enough DSI's would subscribe to the alternative rate to enable the alternative to be adopted.

Decision

A customer charge has been included in the IP-83 rate in order to enhance BPA's revenue stability. DSI arguments that a customer charge violates their Power Sales Contract are without merit. Modification of the design of the customer charge allows for some variability by the nonaluminum DSI's.

Issue #2

What is the appropriate design of the IP-83 customer charge?

Summary of Positions

In the initial proposal, BPA included a customer charge for puchasers under the IP-83 rate based on Operating Demand. BPA, E-BPA-7, 39. The DSI's opposed any customer charge unless it is agreed to as part of an alternative rate package. Mizer & Blevins, DSI, E-DS-15, 1-2. The NWU's, in their prefiled testimony, proposed that the customer charge should be based on Contract Demand. Wolverton, NWU, E-NW-02, 5; McCullough & Wolverton, NWU, E-NW-24R, 11. BPA modified its proposal to be based on the higher of the forecasted Operating Demand or the agreed upon Operating Demand. BPA, Evaluation of the Record, 189.

Evaluation of Positions

Operating Demand

BPA proposed that the customer charge be based on Operating Demands. The Operating Demands are the product of negotiations between BPA and the DSI's. BPA must agree to any lowering of Operating Demands below the 1981-1982 contractually specified Operating Demands. It was BPA's intention to require the DSI Operating Demands to be in total greater than or equal to the rate case forecast. If the aggregate Operating Demands requested by DSI's were less than the forecast, BPA would have to find a means of distributing the divergence among the customers. One such method would be to increase each customer's requested Operating Demand based on the divergence from the 1981-82 Operating Demands. McLennan, BPA, E-BPA-16, 2-6.

Much of the criticism of BPA's proposed customer charge focused on the need to negotiate Operating Demands. The DSI's objected to the unpredictability of the customer charge, pointing out that no DSI is able to predict how it will be affected by the customer charge because of the need to negotiate Operating Demands. Mizer and Blevins, DSI, E-DS-15, 2. The NWU argued that if the customer charge is tied to Operating Demand, any acceptance by BPA of a request for reduction could cause dissension among the customer groups. Wolverton, WNU, E-NW-02, 5-6.

Another problem with the use of Operating Demands is the ratchet effect inherent in that design. Basing the customer charge on Operating Demand would encourage operation up to the Operating Demand. However it discourages increases in Operating Demands. A customer may be reluctant to increase its Operating Demand because the customer charge would penalize later reductions in load. Thus, this design may actually discourage high levels of operation in some circumstances. BPA, Evaluation of Record, 188.

Contract Demand

In order to cure some of the flaws identified with using Operating Demands, alot of attention was focused on basing the customer charge on Contract Demands. The NWU provided two justifications for using Contract Demand to collect the customer charge from the DSI's. First, the Contract Demand represents the "ultimate obligation" that BPA faces to provide power to the DSI's. Thus, BPA's decisions regarding planning and operating of the system reflects this "ultimate obligation." Second, unlike Operating Demand, Contract Demand is stable. A customer charge based on Contract Demand would encourage a high level of stable operation because it would reduce the variable component of rate regardless of the current level of operation. Wolverton, NWU, E-NW-02, 5-6.

BPA agreed that there are advantages associated with the NWU's proposal to establish a customer charge based on Contract Demand. Long-term resource planning tends to be based on three quartiles of DSI Contract Demand. Using Contract Demand to establish the customer charge would reflect the cost causation of BPA's long-term resource decisions. The level of the IP-83 rate is greatly dependent on the DSI load forecast, because of the effect of the DSI forecast on the level of surplus firm power and because BPA is forecasting it will be unable to sell all of the surplus firm power at fully allocated costs. A customer charge based on Contract Demand will make the DSI load forecast less crucial because the actual average IP-83 rate would vary with the size of the actual load. Metcalf, BPA, E-BPA-46R, 11-12.

Use of Contract Demand would also alleviate the two practical problems associated with using Operating Demand. It would remove the customer charge from the unpredictable and potentially controversial Operating Demand negotiations. It would also eliminate the ratchet effect associated with Operating Demand. If based on Contract Demand, the rate design would send a consistent price signal as to the cost of the next kilowatt and kilowatthour, and that signal would be significantly less than the average DSI rate. Metcalf, BPA, E-BPA-46R, 11. Thus, all customers would be encouraged to operate at the maximum level at all times.

The disadvantage of using Contract Demand is that it appears inequitable in that a customer who is operating at a low level would pay a higher average rate. Customers operating at a low level or not operating at all because of economic circumstances might decide to terminate their contracts with BPA rather than pay the customer charge. Metcalf, BPA, E-BPA-46R, 11-12.

In order to alleviate this problem, the OPUC argued that BPA should reopen negotiations over the DSI contracts to allow reductions in Contract Demands for DSI's whose Contract Demands exceed their current ability to take power. They argued also that if a customer cannot afford to pay for the long run costs it imposes on society, then the socially appropriate long run decision is permanent closure. Opening Brief, OPUC, B-OP-01, 15-16. Such renegotiation of contracts would not alleviate the problem associated with using Contract Demands for those DSI's operating at a low level because of economic circumstances. Plant closures caused by the customer charge could have an adverse economic affect because of the current surplus of firm power and the possibility that the plant might have later become economically viable if it had not been forced to commit itself now.

Forecasted Operating Demand

In an attempt to combine most of the positive features of Operating Demand and Contract Demand, BPA proposed to base the customer charge on the greater of the forecasted Operating Demand or the agreed upon Operating Demand. This design when combined with the higher DSI load forecast: (1) will minimize the impact on customers forecasted to operate at low levels compared to a charge based on Contract Demand; (2) will eliminate the uncertainties associated with Operating Demand negotiation; and (3) will provide an incentive for the DSI's to operate at high levels. BPA, Evaluation of Record, 189.

Operating Level

One problem not completely addressed by this alternative is the ratchet effect of using Operating Demand. Even with the higher load forecast, a DSI may wish to operate above the forecast if it would be free to reduce operation later without penalty. This problem could be solved by basing the customer charge on the greater of the forecasted Operating Demand or actual Operating Level (billing demand). This would provide BPA with the needed revenue stability while eliminating the negative incentives associated with the use of Operating Demand.

Decision

The customer charge in the IP-83 rate has been modified to be based on the greater of actual Operating Level or a percentage of the Operating Demand forecast in the rate proceeding. A list of customer-by-customer forecast Operating Demands for Period A and Period B is included as an appendix to the IP-83 rate schedule.

Issue #3

How much revenue should be recovered through the customer charge?

Summary of Positions

In the initial proposal, BPA set the customer charge to recover the difference between total costs allocated to the lower three quartiles and the revenue which would be recovered by applying the PF rate to the billing determinants for the lower three quartiles. BPA, E-BPA-7, 39; Metcalf, BPA, E-BPA-32, 36-38. The NWU believes the customer charge component of the industrial rate should be increased and the variable component decreased. Wolverton, NWU, E-NW-02,4-5; McCullough & Wolverton, NWU, E-NW-24R, 10-11.

Evaluation of Positions

The NWU advocate an IP rate design that ensures that BPA will collect the revenue requirement from the industrial class and provide an incentive for these companies to operate in a stable and predictable manner as the economy fluctuates. As such, the NWU support BPA's proposed customer charge. However, they suggest the customer charge is not adequate. The NWU propose shifting more of the costs away from variable charges to a fixed charge. A rate design that reduces the variable charge, and thus the incremental cost of operating in the Pacific Northwest, will provide an incentive for the DSI's to operate in a baseload manner once BPA has made the forecast that they will operate. Wolverton, NWU, E-NW-02, 4-5; Wolverton, NWU, TR 8524-8525; Opening Brief, NWU, B-NW-01, 60. They recommend setting the energy component of the IP-83 rate equal to the lessor of the nonfirm rate or the IP cost-based rate. The remaining revenue requirement would be collected through the customer charge. McCullough & Wolverton, NWU, E-NW-24R, 11-12. The NWU justify setting the variable rate at the lessor of the Standard nonfirm rate or the cost-based IP rate, as this rate would allow BPA to sell the power elsewhere, if the DSI curtailed first quartile or firm service, without a loss of revenues. Wolverton, NWU, TR 8558.

In the intitial proposal, BPA proposed a customer charge based on the difference between the cost allocated to the bottom three quartiles and the revenue that could be recovered by applying the PF rate to the bottom three quartiles. Under this proposal, BPA and the DSI's share the risk of curtailments. By basing the variable component of the IP-83 rate on the PF-83 rate, the risk of revenue underrecovery to BPA is approximately the same for the PF and the IP classes. BPA, E-BPA-7, 39; Metcalf, BPA, E-BPA-32, 36-38. The NWU suggest that BPA should design the IP rate such that the risk of underrecovery from the DSI's is less than the risk from the PF class.

Decision

The customer charge has been designed to collect the difference between the costs allocated to the lower three quartiles and the revenue which would be collected from applying the PF rate to that level of usage. This ensures collection of the accounting net costs of the exchange from the DSI's and shares the risk of curtailment with the DSI's. Currently, BPA takes almost all of these risks. The NWU proposal, which would have shifted virtually all risk to the DSI's, would be inequitable in that BPA assumes such risks for its utility customers.

Issue #4

Should the customer charge apply to the total DSI Operating Demand?

Summary of Positions

The DSI's asserted that BPA proposed to collect the customer charge based on all four quartiles of DSI load. The DSI's believe that the customer charge should not be collected from the top quartile. Mizer & Blevins, DSI, E-DS-15, 2.

Evaluation of Positions

The DSI's object to application of the customer charge for top quartile service since such service is interruptible by either party. Mizer & Blevins, DSI, E-DS-15, 2. They also argue that the customer charge would be onerous to some DSI's like Penwalt, whose operations vary, and this could result in a reduced market for BPA. Locke, DS, E-DSI-6, 3.

BPA responded that all of the costs assigned to the customer charge are costs allocated to the lower three quartiles and noted that some firm power costs are recovered in the first quartile because of the melded nature of the rate. BPA, Evaluation of Record, 190-191; Mizer, DSI, E-DS-14, 19. A compromise between these two positions would be to apply the customer charge only to that portion of the DSI load equal to the ratio of the costs allocated to the lower three quartiles to total costs allocated to the customer class. One disadvantage of any reduction from the total forecast Operating Demand is that a lesser amount of revenues is protected. This problem is alleviated by the fact that the amount of DSI revenue requirement assigned to the customer charge increased from BPA's supplemental testimony to the final rates from 36.5 percent to 39.4 percent because of more costs being assigned to the lower three quartiles and a lower Priority Firm Power rate.

Decision

The customer charge has been modified so that it is based on 89.4 percent of the forecasted load to reflect the fact that 10.6 percent of the IP-83 revenue requirement is associated with the first quartile (before application of the reserve credit). This allows for customer load variations without penalty to the extent that those variations do not cause BPA to fail to recover firm power costs. Customers will also be allowed to prospectively shape their forecast among the months to allow for seasonal variations. This compromise will continue to provide BPA with a considerable amount of revenue certainty while at the same time allowing some flexibility to the customers. It will also alleviate any problems associated with small variations or imperfections in the disaggregated forecast used as a basis for the customer charge.

BPA understands the concerns of the DSI's regarding the implementation of the customer charge. Although BPA cannot continue to shoulder the entire risk of DSI underruns, it is appropriate that BPA share those risks. In addition, BPA has taken measures, as explained in this document, to mitigate the impact of the customer charge by providing the DSI's greater operational flexibility.

Issue #5

Should the customer charge apply during a restriction?

Summary of Positions

BPA proposed to base the customer charge on Operating Demand regardless of BPA restrictions. Metcalf, BPA, E-BPA-32, 35. The DSI's objected to the application of the customer charge to restricted load. Mizer & Blevins, DSI, E-DS-15, 2.

Evaluation of Positions

The DSI's assert that the customer charge should not apply to restricted load. They argue that it is entirely inappropriate for BPA to charge for power not delivered. Mizer & Blevins, DSI, E-DS-15, 15.

BPA responded that the DSI's are compensated for the value of their restriction rights through a lower overall rate. Therefore, to reduce the customer charge when BPA exercises its contractual restriction rights is unnecessary. BPA, Evaluation of Record, 190-191. However, this argument overlooks two facts. First, applying the customer charge to restricted load will increase the average rate during periods of restriction. A reduction of the DSI rate for interruptibility makes it unnecessary to reduce the DSI rate during periods of restriction, but it appears inequitable to increase it during those periods. Second, the purpose of the customer charge is to protect BPA's revenues in a situation where BPA is unable to market power lost because of DSI load underruns. Metcalf, BPA, E-BPA-32, 38. Clearly, this is not a problem during periods of restriction.

Decision

The customer charge has been revised so that it does not apply to restricted load, because such application would be inequitable and contrary to the purpose of the charge.

b. First Quartile

BPA does not plan or acquire resources to serve the first quartile of the industrial load. Instead, the first quartile is served by: (1) use of a combination of provisional drafts and nonfirm; or (2) use of surplus firm energy load carrying capability (FELCC).

(1) Service to the First Quartile

Issue #1

Should the DSI's top quartile be assigned the cost of surplus firm resources?

Summary of Positions

In the initial proposal, purchasers under the IP rate schedule are allowed to choose between two sets of rates for each rate period depending on how they choose to have their first quartile served. One rate is available for customers selecting first quartile service with the usual combination of provisional drafts and nonfirm energy, and the other is for customers requesting first quartile service with surplus FELCC. Metcalf, BPA, E-BPA-32, 35. The NWU assert that allowing the DSI's the option of selecting first quartile service is inappropriate and shifts the cost of the surplus from the DSI's to the other customers. Schultz, NWU, E-NW-07, 3.

Evaluation of Positions

The NWU objects to providing the DSI's with two sets of rates during the rate period, depending on first quartile service. By providing two rates, and charging more for surplus FELCC service, the DSI's receive a lower power rate under BPA's rate schedules than BPA could receive under the power sales contracts. Schultz, NWU, TR 6729. The effect of this decision, during a period of unsold surplus, is to provide the DSI's with firm service at the less expensive nonfirm rate. Schultz, NWU, E-NW-07, 4. Another consequence is that BPA is left with surplus firm energy that is unmarketable at its fully allocated cost. According to the NWU, this results in shifting the recovery of these surplus costs from the DSI's to BPA's other customers. Schultz, NWU, E-NW-07, 3. However, the majority of the costs incurred due to BPA's projected inability to sell firm surplus at its fully allocated cost, are allocated to the DSI's. See, discussion supra.

Regardless of the resources assumed to serve the first quartile, BPA would retain its restriction rights. Yet the NWU advanced no methodology for valuing those rights. The NWU also did not address the basic inequity of having the DSI rate drastically increase solely because BPA has surplus resources.

Decision

The IP-83 rate has a separate rate for firm first quartile service as in the initial proposal. This rate structure reflects BPA's restriction rights in the rate for service with the usual combination and is consistent with the DSI contracts.

Issue #2

What level of top quartile service should be forecasted?

Summary of Positions

BPA forecast approximately 76 percent service to the first quartile based on an analysis of 40 water years. The DSI's argue that 100 percent service should be forecasted because of BPA's assumption that some surplus firm will remain unsold. Mizer, DSI, E-DS-14, 19.

Evaluation of Positions

The DSI's argue that when a DSI purchases the entire top quartile, "BPA is charging the DSI's twice for the same power, once by including the cost in setting the rate for service to 3.76 quartiles and once again by collecting the same rate when the DSI purchases the entire top quartile." Mizer, DSI, E-DS-14, 19.

The DSI's are correct operationally that the top quartile represents a potential market for surplus firm power. However, even if the unsold surplus was used to serve the top quartile, 100 percent service would not result in some water years.

Decision

Service to the first quartile has been forecasted based on an analysis of 40 water years, as in the initial proposal. However, the first quartile is also modeled as a market for firm surplus which is forecast to be sold in the nonfirm market. This results in a much higher percentage of service to the first quartile.

(2) Pricing the First Quartile

Issue #1

How should BPA price the industrial first quartile when served with nonfirm and provisional drafts?

Summary of Positions

Since BPA does not plan or acquire resources to serve the first quartile of the DSI load, only transmission costs are allocated to this portion of their load in BPA's COSA. In the WPRDS, BPA assigns a price to the first quartile based on the revenues BPA could have received if the energy had been sold in alternative markets. For the initial proposal, the opportunity cost associated with serving the first quartile was approximated by pricing service with nonfirm energy at the generation portion of the monthly average nonfirm rate and by pricing service with provisional drafts at the generation portion of the NF-83 spill rate. Metcalf, BPA, E-BPA-32, 7-9; BPA, E-BPA-7, 17-18, 40. The NWU's said that pricing service to the first quartile with provisional drafts should reflect BPA's foregone revenue plus the cost of providing the service. The generation portion of the Standard nonfirm rate is a reasonable surrogate for the weighted total of these revenues and costs. Schultz, NWU, E-NW-07, 5-6. In their prefiled testimony, the PPC supported the NWU's proposal and identified conservation as another cost associated with serving the first quartile of the DSI load. Wolverton & O'Meara, PPC, E-PP-01, 24. The DSI's believe the embedded cost of the resources used to support service to the first quartile is a more appropriate and stable approach than using an opportunity-cost approach for pricing the first quartile. The average energy charge for all FBS resources would be an appropriate measure of the resource cost supporting service to the DSI's first quartile. Mizer, DSI, E-DS-14, 12. In their prefiled testimony, the DSI's further assert that the opportunity cost approach used by BPA overstates BPA's foregone revenues. Opportunity costs associated with serving the first quartile should be computed by actually identifying the revenues BPA would have obtained from other markets, if that energy were not delivered to the first quartile. Mizer, DSI, E-DS-14, 9.

Evaluation of Positions

Assigning costs to the first quartile is a difficult issue because of the unique character of service provided the first quartile. Ideally, the method chosen would reflect the nonfirm nature of the service from a planning perspective, the near-firm nature of the service on an operational basis (that is, service of the first quartile is high on the priority list of uses of nonfirm energy), and the return provisions for the provisional drafts. Unfortunately, it is very difficult to calculate the cost of these service characteristics, either on an embedded cost of service basis or some incremental cost basis.

Thus, the DSI proposal to base first quartile pricing on accounting resource cost is very appealing. However, the question of what resource costs to include is a difficult one. The DSI's witness raised at least three possibilities: (1) the average energy cost of FBS hydro; (2) the average energy charge for all FBS resources; and (3) total generation costs of the FBS hydro and thermal resources. Mizer, DSI, E-DS-14, 12-13. The same witness advocates establishing the NF-83 rate for sales of nonfirm energy to utilities based on BPA's average generation cost including exchange resources. Mizer, DSI, E-DS-13, 17. He gives no reason why BPA should charge the DSI's less for nonfirm energy than it charges utilities, when the DSI's receive a higher priority service than the vast majority of utility sales.

Equity considerations compel the pricing of the top quartile to be similar to the price BPA charges for other nonfirm energy sales, which leads to the opportunity cost concept of top quartile pricing. There are two extreme positions on how to calculate the opportunity cost of top quartile service. The first views top quartile service as "first on" to reflect the high priority given those sales. NWU's take this approach in arguing that the provisional drafts should be priced at the Standard rate. The NWU's argued that the Standard rate fairly reflects the cost of provisional draft service because depending on the water conditions, the cost of the provisional drafts would include Displacement sales, Spill sales, Standard sales, operation of high-cost thermal units, and the need to take expensive interchange energy. Schultz, NWU, E-NW-07, 5. This analysis overlooks the fact that in some water years some of the energy would be spilled. Mizer, DSI, E-DS-14, 10. In cross-examination, the NWU's witness admitted that he knew of no high incremental cost resources that BPA could operate during the rate period to serve the top quartile. He also had no evidence that interchange energy could be needed to support the shift. Schultz, NWU, TR 6736.

In the other extreme, top quartile service is viewed as being "last on." The DSI's conducted such an analysis and concluded that the opportunity cost of top quartile service is 4-7 mills/kWh. Mizer, DSI, E-DS-14, 10. There are two fundamental problems with this kind of analysis. First, it ignores the high priority given to top quartile service, and, second, it assumes that, in the absence of the top quartile as a market for nonfirm energy, no additional markets for nonfirm energy would have been developed. Examples of such alternatives include a different generation mix in the Pacific Northwest, Schultz, NWU, E-NW-25R, 2-3, and building additional Intertie capability. Thus, by focusing only on very short-run conditions, the DSI's underestimate the opportunity cost of first quartile service.

A reasonable compromise would be to price the first quartile at the generation component of the annual average nonfirm rate. This methodology is equitable with respect to other purchases of nonfirm. It is not tied to any particular nonfirm rate structure (i.e. Spill rate or no Spill rate), and avoids the difficult arguments concerning the cost and value of the provisional drafts. This estimate of opportunity cost will avoid the kind of swings noted by Mizer in a "short-run-last-on" method, Mizer DSI, E-DS-14, 11-12, but still reflects changes in the overall cost and value of nonfirm energy better than any single resource cost method. This method also obviates the need to assign a value to the reserves provided by the first quartile because the nonfirm quality of service is already reflected in the pricing.

The PPC objects to this methodology arguing that because the first quartile is a fairly constant load, most of the nonfirm power used to serve the first quartile could be sold at the Standard or higher rates. Therefore, they argue that the pricing of nonfirm energy supplied to the first quartile should reflect the timing of that service. Reply Brief, PPC, R-PP-01, 13. The PPC's analysis is incorrect. Service with provisional drafts is provided during months when BPA could often market power to other customers at the Standard rate. However, BPA could not market this power to other customers during those periods without return provisions similar to those provided by the DSI's. Thus, the opportunity cost of such sales should be based upon BPA's sales opportunities during the periods from which the energy is borrowed or shifted. BPA, E-BPA-7, 17-18. It is not true that service with nonfirm energy occurs during periods of higher than average nonfirm rates. In fact, the monthly generation component of the average nonfirm rate, when applied to the corresponding monthly service to the first quartile with nonfirm enery, resulted in pricing that service at 11.5 mills/kWh for the intial proposal. BPA, E-BPA-7, 59. The corresponding generation component of the overall average nonfirm rate was 11.8 mill/kWh (15.1 mills minus 3.3 mills transmission portion). BPA, E-BPA-7, Appendix RC, RC-75, BPA, E-BPA-7, 57.

Decision

Service to the first quartile has been priced at the generation portion of the average nonfirm rate. This methodology is fair and equitable for service with nonfirm energy, provisional drafts, and surplus firm sold in the nonfirm markets. It approximates the revenue BPA could receive in other markets.

Issue #2

How should BPA price the industrial first quartile when service is provided with surplus FELCC?

Summary of Positions

The cost assigned to the top quartile when served with surplus FELCC is the same unit cost as the lower three quartiles, representing BPA's cost of serving the industrial load with firm resources. BPA, E-BPA-7, 39. In their prefiled testimony the DSI's objected to BPA's use of an opportunity-cost concept when service is provided with the usual combination and use of the cost of firm resources when service is provided with surplus FELCC. Mizer, DSI, E-DS-14, 17. If the opportunity-cost concept is used to price the two methods of service, then the cost associated with service with surplus FELCC approaches or equals zero. At the most, the opportunity cost is the cost savings BPA could achieve by not generating the power. Mizer, DSI, E-DS-14, 15. If the cost of resources is used, then the cost associated with service with surplus FELCC is the least-cost surplus firm resource under the resource "stacking" method. Mizer, DSI, E-DS-14, 18.

Evaluation of Positions

The DSI's are correct that the costs assigned to first quartile service with surplus FELCC in BPA's initial proposal do not reflect the opportunity cost of providing that service unless it is assumed that all the surplus is sold. Their conclusion that the opportunity cost of the service is near zero ignores the fact that even if it all could not be sold at the SP-83 rate, it could be sold in the nonfirm market. As the DSI's pointed out, it is appropriate to assign the least-cost firm resource available under the resource "stacking" method to the first quartile when it is served with surplus FELCC. The least-cost resource available to serve the first quartile is the exchange resource left over after serving the lower three quartiles.

Decision

Service to the first quartile with surplus FELCC has been calculated at the cost of firm exchange resources, as in the initial proposal. It is entirely appropriate to allocate resource costs to firm service while assigning opportunity costs based on nonfirm sales to nonfirm service. The two different methodologies reflect the different kinds of service.

(c) Incentive Rate

Issue #1

Should BPA offer an incentive rate to the DSI's?

Summary of Positions

In their prefiled testimony, the DSI's suggested that, as a means of increasing revenue stability from the DSI's, BPA should develop rate options for the IP rate class. The DSI's would be offered a lower rate in exchange for commitments to operate at a high level during the rate period. The DSI's proposed two rate options. One rate option would be a cost-based rate (termed the Standard Industrial Rate by BPA, and Rate A by the parties). The other rate option would be a lower rate that provides an incentive for the industries to operate (the Industrial Incentive Rate or Rate B). Mizer & Blevins, DSI, E-DS-15, 6-7. In rebuttal testimony BPA and the NWU's agreed that under some circumstances an incentive rate for the DSI's could be beneficial both for BPA and the DSI's. Metcalf, BPA, E-BPA-46R, 9; Lisbakken, et al., NWU, E-NW-26SR, 2. The WWPUD's felt BPA should not adopt any incentive rate at this time, including the Rate B proposed by the DSI's. Hutchison, et al., WWPUD, E-WW-02R, 29.

Evaluation of Positions

The DSI's argue that the commitment to a high level of production brought about by an incentive rate will allow BPA to know in advance the revenues it will receive from the DSI's, it will increase the subsidy provided by the DSI's, and it will result in a higher level of service to the first quartile. Mizer & Blevins, DSI, E-DS-15, 12-13. BPA agreed that an incentive rate to the DSI's had "the potential of increasing BPA revenues and revenue stabilities while at the same time allowing for greater DSI operations through a lower rate for electricity." Metcalf, BPA, E-BPA-46R, 9. The NWU supports the idea of the alternative rate as a safety net if the expected recovery of aluminum prices does not occur. Lisbakken, et al., NWU, E-NW-26SR, 16.

On the other hand the WWPUD's assert that an incentive rate would constitute setting rates below cost and would not comport with sound business principles. It would be inequitable, would invariably cause discord and dissension, and may result in less revenues to BPA. Hutchison, et al., WWPUD, E-WW-02R, 29. In their reply brief, the WWPUD's agree that BPA's proposal disposed of many of their concerns. Reply Brief, WWPUD, R-WW-01, 6-8.

Decision

An opportunity for BPA and the DSI's to agree on a lower rate has been included in the IP-83 rate. The objections of the WWPUD's are valid concerns which have been eliminated or alleviated by adopting safeguards proposed by BPA and the NWU.

Issue #2

How should the rate options for the DSI's be structured?

Summary of Positions

In their prefiled testimony, the DSI's proposed that the incentive rate consist of demand, energy, and customer charges, as well as an incentive reduction based on operating level and a mitigation factor based on sales of surplus firm and nonfirm that BPA could make if the DSI's curtailed load. Mizer & Blevins, DSI, E-DS-15, 14-17. The PGP proposed an alternative DSI rate that would require the DSI's to purchase 80 percent of three quartiles of their Contract Demand on a take-or-pay basis. The rate for 80 percent top quartile service would be based on the market price of aluminum. All remaining power would be sold at the standard nonfirm rate. Garman, et al., PGP, E-PG-06R, 20-21; Opening Brief, PGP, B-PG-01, 31-32.

Evaluation of Positions

In their prefiled testimony the DSI's described a complicated Incentive rate structure containing a demand, energy, and customer charge as well as an incentive reduction and a mitigation factor. Under the Incentive rate, each DSI would commit to an operating level for the 20-month rate period under a take-or-pay basis. The incentive reduction would be a sliding scale reduction in the customer's monthly power bill dependent on the customer's level of commitment compared to historical operating level. The mitigation factor would recognize the additional sales BPA would be able to make if a DSI were unable to operate at the level committed. Mizer & Blevins, DSI, E-DS-15, 14-17.

However, in cross-examination the same witnesses seemed to describe a simpler take-or-pay rate at the same millage rate for all customers. Mizer & Blevins, DSI, TR 6829-6850. It was this simpler proposal which BPA and the NWU responded to. In rebuttal testimony the more complicated rate reappeared. Mizer & Blevins, DSI, E-DS-17R, 5. In the DSI's brief, the Incentive rate grew even more complicated. It has two options, one with a customer charge and one with a sliding incentive discount based on the level of take-or-pay obligation. Opening Brief, DSI, B-DS-01, 15.

It would help in analyzing the revenue impact of implementing the Incentive rate if its design were similar to the Standard Industrial rate. In projecting the increase in forecasted load associated with any incentive rate, only the change in rate level would have to be considered if the rate designs were the same. Such a rate design would be equitable across the class in that all customers would derive a similar benefit from implementation of the Incentive rate.

A sliding incentive discount such as the DSI's propose is unnecessary because the design of the customer charge provides an incentive for all customers to commit to a high level of operation. Another such incentive is embedded in the criteria for implementation of the Incentive rate; that is, it will only be implemented if the committed load is high. A sliding scale incentive could make implementation of the Incentive rate less likely because of sharply reduced revenues from customers forecast to operate at a high level under the Standard Industrial rate.

In rebuttal the DSI's described the proposed mitigation. The mitigation factor would be the difference between the average rate for sales of surplus firm power sold in firm and nonfirm markets and the DSI rate. Including this information in the document that consitutes the basis for commitment would allow each DSI to make a load commitment with knowledge of the full obligations they would incur under this agreement. Establishing the unit charge prospectively also eliminates later disagreements. Mizer & Blevins, DSI, E-DS-17R, 8-9.

The NWU opposes the DSI's proposal for mitigation arguing that it would eliminate any revenue stability gains achieved by DSI load commitments and that it would institute ratemaking outside the 7(i) process. Reply Brief, NWU, R-NW-01, 35. The extent to which mitigation would detract from revenue stability would depend on how well the mitigation tracked the level of alternative revenues. The level of alternative revenues BPA could receive depends on many factors including the kind of water year BPA is experiencing. In fact, it is only during periods when such alternative revenues would be very low that implementation of lower DSI rates would likely benefit BPA and the other customers.

The PGP's alternative to the DSI proposal was also extremely complicated. It was advanced as being "cost-based" because the PGP believes "it will collect projected revenue requirements with projected firm load." The PGP's proposed rate design is somewhat unclear. Although it is described as a two-part rate, different charges are applied to three portions of a customer's load: (1) 80 percent of the lower three quartiles; (2) 80 percent of the first quartile; and (3) any remaining load. The PGP offers no reason to expect that the DSI's would agree to their alternative, which appears to be higher than the proposed Standard Industrial rate except when the price of aluminum is less than 65 cents per pound. Garman, et al., PGP, E-PG-06R, 21. The PGP asserts that this rate should take effect only when all aluminum producing companies accept the proposed rate. Opening Brief, PGP, B-PG-01, 31. They provide no justification for this proposed restriction. This proposed limitation could preclude adopting an incentive rate when such a rate is beneficial to both BPA and the DSI's.

Although the PGP asserts that their proposed rate is cost-based, the rate for first quartile service is tied to the London Metal Exchange (LME) price of aluminum. While the LME may affect the amount of power which the DSI is willing to purchase from BPA, it does not affect or represent BPA's costs.

Decision

The Industrial Incentive rate, if implemented, will be designed identically to the Standard Industrial rate. That is, the Incentive rate will have a customer charge, an energy charge and a demand charge. The unit charge for the customer charge is the same for both rates. The customer charge is applied to 89.4 percent of the forecasted Monthly Operating Demand (adjusted for restrictions) or the Committed Demand, whichever is greater. This design provides the kind of incentive envisioned by the DSI's (lower average rate for greater commitment level) up to 80.9 percent of the forecasted Monthly Operating Demands. The demand and energy components of the Incentive rate are reduced prorata from the corresponding Standard Industrial rate charges to arrive at the lower average rate.

No mitigation provision is provided in the Incentive rate. Under the Incentive rate, the DSI's would commit to a level of operation, and BPA would operate the system to serve that load level. Including a prospectively determined mitigation factor may lead to a revenue underrecovery. The advantage of offering a rate that deviates from cost is the revenue guarantee. Therefore, the DSI's would be expected to pay for the level of operation committed to unless BPA restricts their load. If BPA restricts, the industries would not pay for the load restricted.

The PGP's alternative has not been adopted. The rate is not cost-based, as claimed, and it would be extremely difficult to administer. It is not appropriate for BPA's revenue recovery to be a direct function of the value of metals on the LME. Furthermore, even if such a relationship were reasonable for BPA's aluminum-producing DSI's, it would not be appropriate to base BPA's rate to a chemical company or wood products industry on the current cost of aluminum. Since the rate would in many circumstances exceed the Standard Industrial rate, there would seem to be little probability that the DSI's would be willing to commit to a high load under the PGP alternative.

Issue #3

How should BPA determine the level of the DSI incentive rate?

Summary of Positions

In rebuttal testimony, BPA proposed offering a series of alternative rates based on reductions from the base rate, or Standard Industrial rate. The reductions would start at 2 mills below the average Standard Industrial rate and continue in one mill increments to about 4 mills below the average Standard Industrial rate. BPA would solicit from each DSI its load commitment at each of these alternative rates. Metcalf, BPA, E-BPA-46R, 9. The DSI's proposed that BPA offer a series of cost-based rates based on the revenue requirements for that class at alternative levels of DSI load ranging from an operating level at 100 percent to about 60 percent of its historical maximum operating level. Each company would voluntarily commit to operating at a certain level on a take-or-pay basis in exchange for an incentive reduction. The rate each DSI would pay would depend on the amount of the incentive reduction. In turn the incentive reduction would depend on the percentage of load committed to historical maximum operating level. Mizer & Blevins, DSI, E-DS-15, 16-17; Mizer & Blevins, DSI, E-DS-17R, 6-7; Mizer & Blevins, DSI, E-DS-21SR, 3. The NWU, on the other hand, suggest offering one alternative rate and soliciting load commitments at that level. This rate would reflect the maximum revenues BPA could expect to receive from the DSI's based on DSI load levels using varying assumed power costs. Lisbakken, et al., NWU, E-NW-26SR, 9.

Evaluation of Positions

The incentive rates proposed by the DSI's would be based on the cost of service. To determine the incentive rate levels, BPA would conduct a series of cost of service analyses assuming different levels of DSI load. The load levels would be established based on a percentage (ranging from 60 to 100 percent) of historical maximum operating level. The resulting series of DSI revenue requirements would serve as the basis for calculating the rate levels. Mizer & Blevins, DSI, E-DS-17R, 5. Each level of the incentive rate with the corresponding load threshold would be incorporated into the Record of Decision. Mizer, DSI, TR 6835. When the rates become effective, BPA would allow each DSI the opportunity to voluntarily commit to one of the load thresholds established for the incentive rate. The rate each DSI would pay depends on the percentage of historical maximum demand to which they commit. Mizer & Blevins, DSI, E-DS-17R, 5-7.

The NWU's objected to the methodology proposed by the DSI's for failing to recognize the foregone revenues due to increased DSI load. When the DSI's load increases, their payments to BPA increase; however, BPA's ability to sell that power in other markets decreases. This should be recognized in the methodology. McCullogh & Wolverton, NWU, E-NW-24R, 2.

BPA identified a timing problem in the DSI proposal that produces a bias towards revenue underrecovery. Under the DSI proposal, BPA would establish the threshold levels in the Record of Decision. However, the rate would not be offered until after November 1, 1983. During the interim, conditions may have changed (price of aluminum, marketability of firm surplus, etc.). If economic conditions have worsened since the rate case, the established threshold levels will not be met. On the other hand, if economic conditions improve the threshold will be met, but BPA might have received more revenues under Standard Industrial rate. To eliminate this bias, BPA proposed that the threshold levels not be established in the Record of Decision. Instead, BPA would solicit commitments from the DSI's for load levels for a series of rates starting at about 2 mills below the IP-83 rate and going down in 1 mill increments, about 4 mills. BPA would implement the rate that would produce the most revenue under current conditions. Metcalf, BPA, E-BPA-46R, 10. Another bias toward underrecovery could result from superior knowledge by the DSI's as to where they would operate under Standard Industrial rate. Metcalf, BPA, TR 7795-7798.

The NWU's agreed that BPA should implement the IP incentive rate that maximizes BPA's revenues. In their surrebuttal, the NWU's indicated the only acceptable alternative IP rate would be one that benefits all customers by improving BPA's total revenues. For this reason, the NWU's objected to offering the DSI's a series of rates from which they can choose and to the lack of any criteria for determining the alternative rate. Instead, the NWU's proposed that BPA offer one incentive rate set at a level that maximizes revenue. Offering the DSI's one alternative rate that maximizes BPA's revenues eliminates the potential for the DSI's commitments to misdirect BPA into implementing an Incentive rate below the actual revenue-maximizing rate level. Lisbakken, et al., NWU, E-NW-026SR, 9.

To determine the revenue-maximizing rate, the NWU proposed the following procedures:

1. Determine the current price of aluminum. The NWU recommended using a 30-day rolling average of the London Metal Exchange (LME) spot price adjusted to reflect American market differences. Lisbakken, et al., NWU, E-NW-26SR, 8.

2. Using the load forecasting model adopted by the Administrator on the record, BPA can project DSI loads assuming various power costs. From these load projections, BPA can identify the rate level that the DSI's could be reasonably expected to commit loads, producing the maximum revenues. Lisbakken, et al., NWU, E-NW-26SR, 9. The revenue-maximizing rate should also account for foregone sales of surplus now delivered to the DSI's. To determine revenues from foregone surplus sales, the NWU proposed using BPA's Nonfirm Energy Program to calculate nonfirm revenues with and without the increased sales to the DSI's. The level of firm surplus sales used in determining the lost revenues should include existing contracts and current offers to purchase. Lisbakken, et al., NWU, E-NW-26SR,

11-12. The alternative rate offered to the DSI's would maximize BPA's revenues from DSI and surplus sales.

The NWU's concern about providing more predictability and certainty to the process is valid and their approach provides more predictability than BPA's. However, their approach is too rigid in a number of areas. Their requirement that the precise model adopted in the rate case be used to forecast DSI loads should be modified, because a useful model should be revised to reflect changing conditions. Designating the model to be used in the Administrator's Record of Decision without allowing for changes to reflect future conditions would be counterproductive and would lead to hair-splitting arguments over what constitutes a change in the model and what constitutes a change in the inputs to the model. It is sufficient for the DSI loads under the Standard Industrial rate and the Industrial Incentive rate to be forecasted based on a single up-to-date model which incorporates the production process for each aluminum plant. The NWU concern, that allowing the model to be changed opens the door for DSI manipulation, can be met by requiring that all inputs be based on publicly available data. Reply Brief, NWU, R-NW-01, 36-37.

The second problem with the NWU's proposal is that the requirement to choose <u>the</u> revenue maximizing rate is too rigid. It is possible that the DSI rate which the models show to be the revenue maximizing rate may be just below a rate which fails to increase total revenues. In that situation, the DSI's may not commit to enough load if their analysis of the situation differs only slightly from BPA's. It may be better, in this situation, for BPA to offer a slightly lower rate which also increases total revenues. The appropriate criterion is that BPA should offer the DSI's the rate which maximizes total revenues, taking into account the uncertainty of load to small changes in assumptions.

The last problem with the NWU's proposal is they suggest using the current price of aluminum to project DSI load. A more appropriate assumption concerning the price of aluminum would be the projected price of aluminum over the time period considered. Using the current price of aluminum to project the DSI load could cause BPA to offer a rate different from the revenue-maximizing level.

<u>Decision</u>

In general, the procedure proposed by the NWU will be used to determine the rate level of the DSI incentive rate. First, the forecast price of aluminum over the prospective period of the offer will be determined. Next Standard Industrial rate revenues will be projected using a current load forecasting model similiar to the model used in the rate case. Using that model, BPA's forecast of surplus firm power sales, and the Nonfirm Revenue Analysis Program, BPA will determine the DSI rate which maximizes total revenues, taking into account the sensitivity of the revenue to small changes in assumptions. If that rate is less than the Standard Industrial rate, BPA will then notice the proposed implementation of the Industrial Incentive rate and invite comments.

This process has the flexibility needed to reflect changing circumstances while providing the appropriate structure and certainty. It also eliminates the possibility of manipulation by determining a single possible Incentive rate.

Issue #4

For what length of time should the Incentive rate be effective?

Summary of Positions

The DSI's proposed that the Incentive rate be offered for the entire 20 month rate period. Mizer & Blevins, DSI, E-DS-15, 15; Mizer & Blevins, DSI, E-DS-26SR, 6. In rebuttal testimony, BPA suggested initially offering an Incentive rate for the first 8 months of the rate period (November 1, 1983, through June 30, 1984), then reassessing circumstances before offering an Incentive rate for the remaining 12 months. Metcalf, BPA, E-BPA-46R, 10. The NWU advocate limiting the offer to 6 month periods, permitting periodic and scheduled reevaluation of the benefits under this offer. Lisbakken, et al., NWU, E-NW-26SR, 13.

Evaluation of Positions

The disagreement over the length of the offer between the DSI's on one hand and BPA and the NWU's on the other reflects a disagreement over the purpose of the alternative rate offer. The DSI's view the alternative offer as a trade between the BPA and the DSI's - a lower rate in exchange for revenue assurance and stability. The DSI's believe that the commitment to high levels of load is a service for which BPA should be willing to pay a premium. The longer the commitment, presumably, the greater the premium. Mizer & Blevins, DSI, E-DS-15, 11-12.

On the other hand, BPA and the NWU's agree that in many circumstances, an alternative rate is unnecessary and would reduce BPA's overall revenues. The circumstances which would result in a lower DSI rate increasing BPA revenues -- the Standard Industrial rate slightly too high to allow profitable production of aluminum for many of the aluminum DSI's and BPA unable to sell the displaced power at a price even approaching the IP-83 rate -- could occur during the rate period, but there is certainly no assurance that it will. Given current forecasts of the price of aluminum, the DSI's will operate at a high level through most of the rate period at the Standard rate. Lisbakken, et al., NWU, E-NW-26SR. Because the circumstances that allow the Incentive rate to be implemented to both BPA and the DSI's benefit constitutes a rather narrow window, it is unlikely that such a circumstance would exist for the entire 20-month period. Therefore, if the offer were restricted to the entire rate period, it is unlikely that BPA would find it to BPA's advantage to make such an offer, especially given current forecasts of the price of aluminum.

Decision

It would not be prudent for BPA to offer the DSI's an alternative rate for the entire rate period. If the criteria necessary for an offer to be made are met, an offer will be made for the a period of not less than 6 months, and not more than 1 year. Any time the Incentive rate is not in place, BPA and the DSI's can implement one by going through the appropriate procedures. That is, if the Incentive rate is not implemented on November 1, 1983, one could be implemented at a later date.

Issue #5

What criteria should be used to determine if the Incentive rate should be implemented?

Summary of Positions

The DSI's proposed two criteria for determining if BPA should implement the Incentive rate. One is an increase in revenue from both committed and projected load, if the Incentive rate is offered, over the DSI's revenue requirement determined by BPA. The other is the value to BPA of the certainty of the revenues under the two rates. Mizer & Blevins, DSI, E-DS-17R, 5; Mizer & Blevins, DSI, E-DS-21SR, 4; Mizer & Blevins, DSI, TR 6813-6814. BPA indicated that the decision to make the offer would be at the Administrator's discretion. In deciding to implement this rate, the Administrator would consider not only total projected revenues from the DSI's, but total overall projected revenues and the level of DSI participation at the particular Incentive rate. Metcalf, BPA, E-BPA-46R, 10; Metcalf, BPA, TR 7824, 7836-7838. The NWU believe an objective methodology for making the revenue comparison under the Standard Industrial rate and the Incentive rate should be established. Lisbakken, et al., NWU, E-NW-26SR, 4. Specifically, BPA should indicate a forecasted model for projecting DSI loads and index to determine the price of aluminum. Lisbakken, et al., NWU, E-NW-26SR, 8. A methodology for determining foregone surplus sales revenues if DSI loads increase should be established. Lisbakken, et al., NWU, E-NW-26SR, 10-13. The threshold DSI load levels for triggering use of the Incentive rate should be defined during this rate process. Lisbakken, et al., NWU, E-NW-26SR, 4. The Incentive rate should be implemented if the resulting revenues less foregone surplus and nonfirm sales are greater than the projected revenues from the Standard Industrial rate.

Evaluation of Positions

The DSI's proposed that BPA implement the Incentive rate unless the aggregate DSI revenue from both the committed load under the Incentive rate plus the uncommitted projected load under tbe Standard rate is significantly less than the projected revenue requirement to serve the amount of load. Mizer & Blevins, DSI, E-DS-17R, 5.

In rebuttal testimony, BPA indicated the DSI proposal contained a bias towards revenue underrecovery. The criteria proposed by the DSI's for implementing the Incentive rate does not recognize that in some situations BPA's revenues would not be improved. If economic corditions improve, the DSI's committed revenues under the Incentive rate plus uncommitted forecast revenues under the Standard rate could meet the revenue requirement for this class; however, BPA might have received more revenues if the Incentive rate had not been implemented and all sales had been made under the Standard rate. Metcalf, BPA, E-BPA-46R, 9.

The NWU's asserted that under the DSI's criteria BPA would not have to cover or exceed the revenue requirement to implement the Incentive rate; instead, the revenue BPA will collect if the Incentive rate is implemented need only not be materially below the revenue requirement. Offering a rate to the DSI's with knowledge that the revenues received will not cover the revenue requirement is not prudent business practice and could harm the other customers. Opening Brief, NWU, B-NW-01, 37.

To address the potential for revenue underrecovery, BPA proposed that in making the decision to implement the Incentive rate, the following criteria would serve as guidelines:

(a) total projected revenues from the DSI's would be greater if the Incentive rate were implemented;

(b) total projected revenues from all customer classes increase; and

(c) the Incentive rate offer would attract a high level of DSI participation. Metcalf, BPA-E-BPA-46R, 10.

If criteria (a) and (b) are not met, then Incentive rate alternative would not be offered. The third criterion is not that clear-cut, but would allow the Administrator to consider the number of DSI's benefiting from the offer. Carr, BPA, TR 7878.

In making the determination, after receipt of commitments from the DSI's, BPA would use the most current revenue forecast to determine which rate (Standard Industrial rate or Industrial Incentive rate) would produce the most total revenues from all customer classes. Metcalf, BPA, TR 7824. This would allow incorporating the latest economic and operating conditions in the load forecast to compare revenues under the two rates. Metcalf, BPA, TR 7836. Therefore, both the DSI's decision to commit to the Incentive rate and BPA's decision to implement the Incentive rate would be made with current knowledge about the aluminum market and other factors that affect DSI operations. Carr, BPA, TR 7848.

The DSI's agreed that BPA must consider the impact on total revenues as part of the decision process to determine whether or not to implement an Incentive rate. However, the decision should consider other factors besides increased revenue. The DSI's stated that BPA's proposed criteria for implementing the Incentive rate underestimates the value of the revenues guaranteed under a take-or-pay situation. Mizer & Blivens, DSI, E-DS-21SR, 3.

The NWU's objected to the subjective criteria proposed by BPA to determine when the Administrator will implement the Incentive rate. By not specifying an objective test for triggering the rate, the BPA proposal simply grants the Administrator the authority to determine the DSI rate after the close of the hearings. Without any objective methodology all customers would be harmed. The NWU also assert that the lack of an objective test renders the adoption of the Incentive rate illegal because the rate is set outside the 7(i) process. Lisbakken, et al., NWU, E-NW-26SR, 3-5. To eliminate this problem, the NWU proposed that BPA adopt the standard that the Incentive rate would be triggered only when the DSI revenues from the Incentive rate less foregone surplus firm and nonfirm sales is greater than DSI revenues from the Standard Industrial rate.

Decision

The determination of whether to implement the Incentive rate will be based on a comparison of total revenues with and without implementation of the Incentive rate. Specifically, the Incentive rate will be implemented if committed Incentive rate revenues plus forecast uncommitted revenues less foregone surplus (firm and nonfirm surplus) sales are greater than forecast Standard Industrial rate revenues. DSI load forecasts will be made using BPA's current DSI load forecasting model. Foregone revenues will be calculated using BPA's forecast of surplus firm sales and the Nonfirm Revenue Analysis Program. This procedure, combined with the procedure for determining the Incentive rate to be offered, is well defined and would not violate section 7(i) of the Regional Act.

Issue #6

If the Incentive rate is implemented, should BPA require the DSI's to agree that the Standard rate would be the floor rate for the post-85 process?

Summary of Positions

The DSI's believe the floor rate for the post 1985 proceeding should be based on the "actual cost-based rate paid by the DSI's" during the 20 month rate period. Mizer & Blevins, DSI, E-DS-21SR, 7. Both BPA and the NWU believe the floor rate should be the Standard Industrial rate in effect during the 1984-85 operating year. Metcalf, BPA, E-BPA-46R, 11; Lisbakken, et al., NWU, E-NW-26SR, 14-15.

Evaluation of Positions

The DSI's argue that the floor rate is a legal question that need not be decided now. However, they also assert that the floor rate should be based on the actual cost-based rate paid by the DSI's during the rate period, and that an alternative Incentive rate would be cost-based. It is clear, therefore, that they are prepared to argue that the floor rate be based on whichever rate is actually in place. Mizer & Blevins, DSI, E-DS-21SR, 6-7. The DSI's also agree that an Incentive rate may be beneficial post-85, and that BPA should not foreclose its options.

The NWU's insist that BPA require "each DSI as a condition of receipt of the 'B' [Incentive] rate to waive any future claim that the 'B' rate is its proper floor rate." Lisbakken, et al., NWU, E-NW-26SR. The basic argument in favor of an alternative DSI rate is that BPA and its other customers are "held harmless" from such a low DSI rate if such a rate results in equal or greater total revenue during the rate period than the rate resulting from the usual cost allocation and rate design process. This rationale is lost if adoption of the alternate rate also has the potential to lower the DSI rate after the rate period is over. This could well have a detrimental effect on BPA's other customers. An agreement by the DSI's that any Incentive rate implemented during this rate period would not constitute the post-85 floor rate would not necessarily preclude adoption of an Incentive rate after July 1, 1985, if it met the same kind of conditions as required during this rate period, namely that it increases net BPA revenues.

Decision

The DSI's are correct that the floor rate is a legal issue to be decided later. Nevertheless, any agreement to adopt an alternate rate will include language stating that the floor rate will not be based on such alternate rate. This language is needed to assure that other customers are not harmed by the adoption of an alternate rate.

d. Surplus Sales to the DSI's

Issue #1

Should BPA continue the special offer of nonfirm energy to the DSI's scheduled to terminate October 31, 1983?

Summary of Positions

In the initial proposal, BPA assumed that the special offer of nonfirm energy to serve additional DSI load pursuant to an agreement between BPA and the DSI's did not continue beyond October 31, 1983, as specified in the agreement. McLennan, BPA, TR 4624, 4628, 4632. The DSI proposed that BPA should renew the special offer of nonfirm energy to the DSI's on reasonable terms and conditions. During this rate case, BPA should explicitly indicate the applicable rate under which future special offers could be made. Mizer & Blevins, DSI, E-DS-15, 8-10; E-DS-17R, 11.

Evaluation of Positions

In their prefiled testimony, the DSI's indicated that not all DSI's may be able to resume operations under the final rate effective November 1, 1983 and that BPA should provide a mechanism whereby surplus power would be available to increase DSI load. Mizer & Blevins, DSI, E-DS-15, 8. They argue that to enable otherwise idle load to operate is beneficial to the region and the current special sale of nonfirm energy to the DSI's resulted in increases in employment and BPA revenues. Therefore they argue that to foreclose the possibility of being able to make future offers of this kind or to not clearly indicate BPA's ability to make future offers would not be prudent in light of future uncertainty. Mizer & Blevins, DSI, E-DS-17R, 10-11.

To develop the initial rate proposal, BPA assumed that the special nonfirm energy offer to the DSI's would terminate on the date provided for in the agreement. Although this particular special offer is viewed as nonrecurring, BPA does not mean to exclude the possibility of considering other arrangements for sales of surplus within the Northwest. McLennan, BPA, TR 4632. However, BPA has not yet determined if similar special sales would be made after November 1, 1983, nor has BPA determined the characteristics of future surplus sales. Carr, BPA, TR 5819. Although BPA has not explicitly developed language in the proposed rate schedules providing for future special surplus sales offers, BPA's proposed rate schedules would not prohibit BPA from making these sales.

One potential problem with providing for special surplus sales is the potential customer reaction to the possibility or probability of these offers being made. If customers believe a lower rate wil be available in the future, then their current behavior may be to establish an advantageous position for accepting the offer. By providing for future surplus sales, BPA must be careful not to create an incentive for customers to avoid purchases at the published firm power rates. Metcalf, BPA, TR 5816.

The DSI's have further suggested that BPA should prepare and publish, for public comment, a policy governing short-term surplus sales. They also suggest principles to be included in that policy.

Decision

BPA continues to assume that the nonfirm sales to the DSI's will terminate as of November 1, 1983. No special rate has been included for such sales. However, no steps been taken to preclude them. The decision as to whether a policy will be established and any contractual arrangements governing such sales are outside the rate process.

3. Industrial Hanna Power Rate, IH-83

IH-83 power is a special class of industrial firm power made available to the Hanna Nickel Smelting Company (Hanna) pursuant to section 7(d)(2) of the Regional Act.

Issue #1

At what level should the IH-83 rate be set?

Summary of Positions

BPA, in the initial proposal, set the Industrial Hanna rate (IH-83) equal to the PF-83 rate less than the value of reserve credit. The IH-83 contained seasonally and diurnally time-differentiated demand charges and seasonally differentiated energy charges. No charge for demand would be imposed during the offpeak periods of 10 p.m. to 7 a.m., Monday through Saturday (9 hours), and all day Sunday (24 hours). BPA, E-BPA-7, Appendix C, C-28; BPA, E-BPA-7, 41; Metcalf, BPA, E-BPA-32, 14. In prefiled testimony, Hanna proposed an additional special rate of 7.0 mills/kWh with no demand charge for offpeak purchases up to full Contract Demand for 10-13 hours, inclusive, Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday. This special additional rate also would apply to on-peak purchases up to 10 percent of Contract Demand. Hanna proposed that the additional special rate would apply until Hanna requested more than ten percent of its Contract Demand during peak periods. Wedge, Hanna, E-HN-01, 3; Moke, Hanna, E-HN-02, 6.

Evaluation of Positions

Under 7(d)(2), BPA can offer Hanna a special rate in order to avoid adverse impacts of rate increases pursuant to the Regional Act. BPA believes the proposed IH-83 rate reflects a cost-based approximation of the rate Hanna would pay absent the Regional Act. In the initial proposal, BPA set the IH-83 rate equal to the PF-83 rate less the value of reserves credit. BPA, E-BPA-7,41; Metcalf, BPA, E-BPA-32, 14. Prior to the Regional Act, the DSI's were served from the same resource pool as the preference customers. Metcalf, BPA, TR 5400.

Pursuant to section 7(d)(2) of the Regional Act, Hanna presented testimony requesting an additional special rate of 7.0 mills/kWh to be made available up to full Contract Demand. Wedge, Hanna, E-HN-01, 3; Moke, Hanna, E-HN-02, 6. Hanna indicated that BPA's proposed IH-83 rate would not help open the Riddle plant in the foreseeable future. Wedge, Hanna, E-HN-01, 10. However, the proposed 7.0 mills/kWh rate along with continuing improvement in the nickel market and resolution of labor negotiations would allow Hanna to resume partial operation shortly after November 1, 1983. Wedge, Hanna, E-HN-01, 12-13. In its testimony, Hanna provided a breakdown of the major costs involved in nickel production: power, labor, supply, and administrative costs. With a 7.0 mills/kWh rate, the cost to Hanna of producing a pound of nickel would be $2.62. Under the IH-83 rate, using only offpeak power, the cost to Hanna of producing a pound of nickel would be $2.90. The current price of nickel, based on the London Metal Exchange, is approximately $2.20 - $2.30 per pound. With the upward trend in nickel prices, from the low in December, 1982, of $1.50, Hanna indicated that if production cost can meet market expectation, the Riddle plant would reopen. This would be possible under a 7.0 mills/kWh rate. Wedge, Hanna, E-HN-01, 6-8.

BPA agrees with Hanna's assertion that they would not be able to operate in the near future under BPA's proposed IH-83 rate. In the initial and supplemental proposal, BPA assumed Hanna would not be able to operate until January, 1985. Even then Hanna would only resume partial operation. BPA, E-BPA-3, 35; Hoffard & Moorman, BPA, E-BPA-11S, 13.

Hanna argues that BPA has indicated that serious consideration would be given to rate proposals that demonstrate an increase in revenues from a particular customer, due to reducing their rate below the level resulting from application of the rate directives. Moke, Hanna, E-HN-02, 13. Melton, BPA, E-BPA-10, 8. Hanna submits that under the IH-83 rate, no prediction can be made with any certainty when Hanna will resume operation. Wedge, Hanna, E-HN-02, 10. Until Hanna resumes operations, BPA will not receive revenues from the IH-83 rate. However, under an additional special rate of 7.0 mills/kWh, Hanna could resume partial operation and BPA's revenues from the IH customer class would, therefore, increase. Moke, Hanna, E-HN-02, 13.

Although Hanna's proposal would increase revenue received from the IH-83 rate class, BPA's total revenue collected may not be improved. The revenue received from Hanna would be below the revenue BPA could obtain in alternative markets except when Displacement sales are being made. Thus, Hanna's proposed rate would result in lost revenues to BPA under all but the most favorable of water conditions.

The purpose of the additional special rate was to allow Hanna to resume operation shortly after November 1, 1983. If Hanna could operate under the IH-83 proposed by BPA then a special rate would not be necessary. Thus Hanna proposed eliminating the additional special rate when operation under the IH-83 rate was economical. Hanna would trigger the elimination of the additional special rate by requesting more power than ten percent of Contract Demand during peak periods. Once the IH-83 rate is triggered, all power purchases would be made under that rate level. Moke, Hanna, DS 23-25.

The off-peak periods proposed by Hanna were developed to provide BPA with some degree of flexibility as well as to enable Hanna to operate within these off-peak hours. BPA would determine the specific 10-13 hours during the proposed off-peak period that power would be available. Further, if conditions warranted, BPA could change the hours of availability during the time the additional special rate was in effect. To establish or change the hours of availabilty, BPA would provide Hanna with at least two weeks advance notice. Moke, Hanna, E-HN-02, EWM-02, 2.

Allowing Hanna to take power during off-peak periods, (as opposed to not serving Hanna at all), could prove beneficial to BPA's operation of the system. For one, off-peak service to Hanna could alleviate some of the occasional difficulties BPA experiences with night-time energy return arrangements. BPA also supports the flexibility under Hanna's proposal to change the hours of availability allowing BPA to respond to changing conditions. Thus, BPA believes there are definite advantages associated with serving Hanna with off-peak power.

However, BPA does not agree that the hours identified by Hanna constitute BPA's off-peak period. The off-peak hours identified in BPA's rate schedules are for 9 hours Monday through Saturday, and all day Sunday. BPA, E-BPA-7, C-28. Nevertheless, the hours that Hanna identifies as off-peak all fall within the off-peak period or the shoulder period as identified in the TDLRIC Analysis.

Decision

The IH-83 rate includes two special rate options pursuant to section 7(b)(2) of the Regional Act. The special rate options were developed to allow Hanna to resume operation while at the same time minimizing adverse impacts on the Administrator's other obligations. The Standard IH-83 rate in the initial proposal was maintained. That is, the Standard IH-83 rate was set equal to the PF-83 rate less the value of reserves credit. An additional special rate of 7.0 mills/kWh was also included in this rate schedule. BPA modified the rate schedule to allow Hanna to purchase the 7.0 mills/kWh power under the conditions described in their proposal. Hanna would be able to take up to their full Contract Demand during off-peak hours. During the peak period Hanna would commit to curtailing to ten percent of their Contract Demand. BPA adopted the off-peak hours and conditions proposed in Hanna's testimony for service under the 7.0 mills/kWh rate.

The special additional rate of 7.0 mills/kWh will apply until Hanna requests more than ten percent of Contract Demand during the peak period. At that point all purchases would be subject to the terms and conditions of the Standard IH-83 rate.

4. Firm Capacity Rate, CF-83

BPA's Firm Capacity (CF) rate is available for the contract purchase of firm capacity. Besides being available on a contract year or contract seasonal basis as described in the initial proposal, additional language has been incorporated to allow purchases under a general basis. The months during which general Firm Capacity will be supplied are specified in the power sales contracts. The rate includes a surcharge which applies when a purchaser takes capacity in excess of 9 hours during BPA's peak period (7 a.m. to 10 p.m., Monday through Saturday).

a. Extended Peaking Surcharge

Issue #1

Should BPA update its 9-hour limitation to reflect the latest data?

Summary of Positions

BPA did not update the 1979 study on which its calculation of the nine hour peaking limitation is based. BPA, E-BPA-7, Attachment 1, 187. BPA indicated that it is satisfied with that study and is not intending to update it every year. Metcalf, BPA, TR 7281.

PG&E objected to the nine hour limitation on the grounds that it is based on outdated information. They pointed out that if the calculation were based on the two most recent years in BPA's study (1978 and 1979) a 10-hour limitation would result. Buckingham, PG&E, E-GA-01, 11-12. Consequently, they argue that it is improper ratemaking for BPA to continue to rely on the results of the 1979 study.

Evaluation of Positions

PG&E is correct in asserting that BPA's nine hour limitation is based on somewhat outdated information. However, PG&E has presented no detailed evidence to support its assumption that a reevaluation of the nine hour limitation would yield different results. BPA takes many ratemaking considerations into account when designing its rates. One of those considerations is rate continuity. BPA, E-BPA-7, 2. By retaining the nine-hour period BPA is furthering that rate design objective.

Decision

Although it may be desirable to update all BPA studies on an annual basis, it is not practical to do so. Customers have accepted the manner in which BPA determined the nine hour limitation. Furthermore, retaining the same hourly limitation from one rate filing to the next is consistent with BPA's rate continuity objective. Therefore, it is appropriate to continue to use the results of the 1979 study as the basis of the peaking limitation.

Issue #2

How should BPA calculate its extended peaking surcharge?

Summary of Positions

BPA has proposed basing the extended peaking surcharge on the costs to BPA of supplying capacity for more than nine hours. Those costs consist of the system costs associated with sustained peaking and the costs associated with accepting return energy. BPA, E-BPA-7, 42-43.

The NWU suggested that BPA improperly measured the effect of sustained peaking on the Federal system. Wilson, NWU, E-NW-8, 16. They believe that the extrapolation of the data from the graph on 213 of Attachment 1 to E-BPA-7 should take the form of a curve; it should not be linear as BPA suggests. Reply Brief, PP&L, R-PL-01, 12. In addition, they argue that BPA overstates the cost to BPA of the return energy provision associated with firm capacity contracts. Wilson, NWU, E-NW-8, 16. They state that the charge should not be applied in all twelve months given that the relevant costs are incurred between July and October. Wilson, NWU, E-NW-8, 16. The NWU position is endorsed by PP&L in its briefs. Opening Brief, PP&L, B-PL-01, 36-37; Reply Brief, PP&L, R-PL-01, 11-14.

Evaluation of Positions

Although the NWU and PP&L objected to the manner in which BPA extrapolated the curve for its sustained peaking calculation, they supplied no data to justify their extrapolation. Furthermore, if BPA were to apply the logic advocated by the NWU to determine the system's capability for sustaining a peak for 24 hours a day, it would show, at some point, an increased system capability as the number of hours of sustained peaking were increased. In their reply brief PP&L asserts that "[t]hese findings are plainly wrong." Reply Brief, PP&L, R-PL-01, 12. In effect, PP&L has embraced BPA's point that the curve does not retain the same shape over the 24-hour period in a day. However, the NWU and PP&L fail to show in their testimony how, where, and why the curve changes. They have not provided any data which justifies their particular extrapolation as being more appropriate than BPA's.

In the initial proposal, BPA took into account that the return energy problem is not likely to occur in all 12 months of the year. The numerical basis for the rate, Attachment 1 to E-BPA-7, 226, shows that BPA considered the total system costs from the return energy and then spread those costs over a 12-month period. BPA could, instead, have chosen to seasonally differentiate the surcharge. The result of such differentiation would be no charge for return energy in some months and a higher charge in those months when the charge would be applied.

The NWU's proposal to spread the costs of return energy over the relevant months of the year, Reply Brief, NWU, R-NW-01, 13, would be a reasonable alternative to BPA's proposal. However, while the NWU raises a valid point, the difference between using a yearly average and a seasonally differentiated rate is a matter of pennies per month relative to a rate of dollars per month. BPA, E-BPA-7, Appendix C, C-37. In other instances where there is virtually no difference between the level of a rate for one part of the year and the level for the rest of the year, BPA has not seasonally differentiated the charge. BPA, E-BPA-7, 32.

The NWU's assert that since BPA is in a surplus condition, "[d]uring the rate period, off-peak return merely would substitute nighttime surplus power for daytime surplus power." Wilson, NWU, E-NW-8, 17. However, even in time of surplus, night-time energy return can cause minimum generation problems, turning power which could otherwise be marketed at the SP rate or the NF Standard rate into power that would be marketed at the Spill or Displacement rate, if at all.

PP&L asserted in its reply brief that "marginal cost principles are used for rate design, but not for revenue requirement purposes." Reply Brief, PP&L, R-PL-01, 14. Thus, PP&L contends that the extended peaking surcharge should be based on BPA's actual costs. Reply Brief, PP&L, R-PL-01, 14. In making this argument PP&L overlooks the fact that BPA does not forecast revenues from the extended peaking surcharge.

Decision

BPA has used its linear sustained peaking data presented in Attachment 1 to E-BPA-7. Use of the NWU alternative leads to an inaccurate conclusion if their methodology were applied to the entire hourly range of sustained peaking values (i.e., 0 to 24 hours per day).

It is appropriate for BPA to base the cost of its sustained peaking surcharge on BPA's system costs associated with supplying capacity for more than nine hours and the associated costs of additional return energy.

BPA will continue to assess the extended peaking charge on an annual basis. The charge is so small that ease of administration would dictate that BPA use an annual charge.

b. Treatment of Intertie Costs

In the initial proposal BPA proposed that the CF rate include a separate charge for Intertie costs. In the past, the Intertie costs have been "rolled into" the seasonal capacity charge.

Issue #1

How should BPA treat Intertie costs in its CF-83 rate?

Evaluation of Positions

BPA included a separate rate for Intertie service in its proposed CF-83 rate. The purpose of separating the charge from the seasonal capacity rate is to make the two firm capacity rates (annual and seasonal) more generic. Stevens, BPA, E-BPA-31, 7. PG&E has objected to BPA's charging extra-regional utilities a higher rate for CF service than the rate paid by Northwest customers. Buckingham, PG&E, E-GA-01, 9-11. The NWU argue that BPA should either impose a separate Intertie charge for each rate applicable to extra-regional sales, Schultz, NWU, ENU-7, 11, or, alternatively, set a single rate for deliveries over BPA's system, regardless of delivery point. Schultz, NWU, E-NU-7, 13.

Evaluation of Positions

PG&E contends that the Intertie benefits both the Northwest and Southwest customers. Since BPA uses a "rolled-in" transmission system (for which the Southwest customers helped pay), PG&E feels that it is appropriate for the Northwest customers to share in the Intertie expenses. Buckingham, PG&E, E-GA-01, 9-11. Otherwise, Southwest customers should be exempt from paying for fringe facilities associated with deliveries of power to Northwest customers.

PG&E is correct in its assertion that in BPA's initial proposal the seasonal capacity charge included both an Intertie adder and a component representing the equalized cost of Pacific Northwest fringe and delivery facilities that are not used by extra-regional utilities. Although it would be technically feasible to develop an Intertie adder for all rates that could be used for sales in the Pacific Northwest and Southwest, BPA has developed such an adder only for the two capacity rates. This adder is included in the CF rate because firm contracts exist both for service over the Intertie and for service in the Pacific Northwest. The adder is included in the CE rate because its calculation depends on the CF rate. BPA, E-BPA-7, 34.

The NWU have primarily objected to the fact that proposed SP-83 and NF-83 rates do not include an Intertie adder whereas other rates such as the CF and CE rates do. NWU objects to the lack of an Intertie adder for extra-regional sales because Northwest utilities must pay transmission rates to use BPA's system to make sales outside the region. California utilities, by contrast, are not required to pay BPA for those same costs associated with BPA power. Schultz, NWU, E-NU-7, 10-11.

BPA recognizes the merit of the NWU proposal to include an Intertie adder on all extra-regional sales. However, BPA also recognizes the depressive effect that such a charge might have on sales which have not yet been consummated. Consequently, BPA has proposed that the adder be applied only to those firm sales for which contracts have already been executed (i.e., CF sales) and to sales dependent on the CF rate (i.e., CE sales).

Decision

The Intertie adder in the CF-83 rate has been calculated based on the difference in unit costs between the Intertie costs and the portions of the equalized demand charge attributable to Pacific Northwest fringe and delivery facilities. This methodology ends the inconsistency in treatment noted by PG&E, while retaining the major cost allocation differences between current annual and seasonal capacity customers. In addition, this methodology will permit the use of more generic rate schedules.

5. Emergency Capacity Rate, CE-83

The Emergency Capacity (CE) rate is available for the purchase of capacity on a weekly basis. Emergency capacity may be used either when an emergency exists on a purchaser's system or when the purchaser wishes to displace higher cost resources. The rate was calculated in the initial proposal by increasing the CF rate by 30 percent and converting the costs to a weekly charge. No surcharge is included in the CE rate.

Issue #1

Has BPA correctly calculated its charge for Intertie service?

Summary of Positions

In the initial proposal BPA calculated the Intertie charge by dividing the total monthly costs by 4 weeks in order to arrive at a weekly charge. The NWU contended that BPA's calculation is incorrect. They stated that there are 4.33 weeks in a month and, therefore, 4.33 should be used in the calculation. Wilson, NWU, E-NU-8, 20.

Evaluation of Positions

The NWU are correct in their assertion that 52 weeks divided by 12 is 4.33, not 4.

Decision

BPA has reflected the data presented by NWU in its final proposal.

6. Firm Energy Rate Schedule, FE-83

BPA proposed eliminating the Firm Energy (FE) rate schedule in the initial proposal. BPA has used this schedule for pricing station service and computing the value of exchange accounts. BPA is proposing to replace the FE rate schedule with the PF and the NR rate schedules.

Issue #1

Is it appropriate for BPA to eliminate its Firm Energy (FE) rate?

Summary of Positions

BPA has proposed eliminating the FE rate schedule and replacing it with the PF and the NR rate schedules. One of the major uses of the FE rate is to price the station service for the Centralia generating plant. BPA believes that the quality of service currently provided under the FE schedule is basically the same as that provided under either the PF or NR rates. BPA, E-BPA-7, 36.

The ICP objected to BPA's proposed elimination of the FE rate because they believe that the quality of service is quite different. Wilson, ICP, E-IC-06, 3.

Evaluation of Positions

First, the ICP notes that the power sales contract between PP&L and BPA refers to the purchase of energy, not capacity. Wilson, ICP, E-IC-06, 1. They believe it would be inappropriate for BPA to charge for capacity which it has no obligation to supply and which has not been requested. Wilson, ICP, E-IC-06, 2-3. Second, the ICP points to a section of the power sales contract which refers to the fact that the intial standby rate can "be replaced by a new rate for standby service." Wilson, ICP, E-IC-06, 3. The ICP contends that this clause and the "most favored nation" clause in the General Contract Provisions (GCP) preclude BPA from charging PP&L at the NR rate for this firm energy while making the same quality of power available to preference customers at the PF rate. Wilson, ICP, E-IC-06, 3-4.

The ICP's prefiled testimony focussed on that portion of the GCP's which states that delivery of standby service shall be made "at the rate specified in any rate schedule available under new contracts for service of the same class, quality, and type provided for in this contract." Wilson, ICP, E-IC-6, Attachment 1, 23.

The ICP's contention that BPA is proposing multiple rates for FE service is erroneous. Under BPA's proposal, PP&L would only be eligible for NR service. In their reply brief PP&L notes that the contract states that the applicable rate should be that which is "for service of the same class, quality, and type provided for in this contract." Reply Brief, PP&L, R-PL-01, 15. Thus, PP&L argues that it should receive service under the PF rate. However, PP&L is narrowly defining the term service. By BPA's definition, the term "service" may appropriately include a description of the type of customer being served. Otherwise, it would appear that there should be no difference between the levels of the PF, NR, and RP rates. Each rate is for firm power. The only difference in "service" between these rates has to do with who is served by that power. Thus, BPA's distinction remains valid.

Station service, at times, is a low load-factor load. In fact, BPA included a capacity component in the FE-2 rate. PP&L did not argue that they should not pay the FE-2 rate because of the capacity component. However, the power sales contract specifically states that the contract is for energy. There is no mention of capacity in the contract. Therefore, while BPA should apply a capacity charge for such service in other instances, in this particular case there can be no such charge.

Since:

(1) it is only the customers who previously used the FE rate schedule who will be exempt from the capacity component of the NR rate,
(2) BPA has not exempted purchasers of station service power under the PF rate from the PF capacity charge, and
(3) BPA does not anticipate providing "firm energy" service to other customers in the future, it is clear that there are not, contrary to

PP&L's assertions, two rates available for service of the "same class, quality, and type."

Decision

BPA has abolished the FE rate schedule and replaced it with the PF and the NR rate schedules. The FE schedule does not fairly represent the type of service which is actually provided by BPA. The ICP represents a different class of utility from BPA's public agency customers which would be eligible for the PF rate for small new loads. Thus, BPA will apply the energy charge of the NR rate schedule to PP&L's purchase of stand-by energy for Centralia station service.

The FE rate was based on the PF rate calculated at 100 percent load factor. Thus, the effect of elimination of the FE rate is minimized to BPA's customers eligible for the PF rate that have existing contracts referring to the FE rate. The impact of abolishing the FE rate is significantly greater to customers who must purchase under the NR rate. Therefore, the demand charge has been eliminated for those customers with existing contracts referring to the FE rate, who must purchase under the NR rate.

7. New Resource Firm Power Rate, NR-83

The New Resource Firm Power rate schedule (NR-83) is the schedule that applies to the IOU's load growth and new large single loads of BPA's public agency customers. The design of this rate schedule was not straightforward because no peak period service is forecast and no demand costs are allocated to it. Issues related to the billing factors for NR-83 service are discussed in section E.3.

Issue #1

How should the NR-83 rate be determined?

Summary of Positions

In BPA's initial proposal, the NR-83 rate schedule included an equalized demand charge although no power was forecasted to be taken during peak hours. The energy charge was calculated based on the SP-83 charge. BPA, E-BPA-07, 45; Metcalf, BPA, E-BPA-32, 13, 43.

The ICP argued that the NR-83 rate should be based on the cost of resources needed to provide NR-83 service. Lauckhart, ICP, E-IC-02, 2; Lauckhart, ICP, TR 7546-7548; Opening Brief, PSP&L, B-PS-01, 4-5, 7.

Evaluation of Positions

Because there was a contractual requirement for energy only, no capacity costs were allocated in the COSA to serve this load. Metcalf, BPA, E-BPA-32, 42. However, BPA is not assured that Puget Sound Power and Light (currently the only customer forecast to purchase NR-83 power during the rate period) or other potential customers will not require service during on-peak periods. Contractually, computed requirements customers are, at the present time, permitted to take power during peak hours up to their Computed Average Energy Requirement while having a Computed Peak Requirement of zero. To provide for this possibility, BPA proposes that "the New Resource rate must be of general applicability for any firm load that conforms to the NR-83 availability requirements." The need for a rate of general applicability was resolved by establishing a demand charge set equal to the equalized PF demand charge and basing the energy charge on the SP-83 rate. Metcalf, BPA, E-BPA-32, 43.

The ICP observed that the proposed NR-83 rate schedule with the equalized PF-83 demand charge is projected to recover about $18.7 million, yet the revenue requirement for this class of service is only about $10.4 million. Lauckhart, ICP, E-IC-02, 3. Puget Sound Power and Light's Opening Brief again stated that the proposed NR-83 rate would recover more revenue than the costs allocated to serve the load. Opening Brief, PSP&L, B-PS-01, 5.

The reason the forecasted revenue was greater than the allocated cost stemmed from the need to have a demand charge in the rate schedule and need for the demand charge to equal the equalized PF and CF demand charge. BPA, E-BPA-7, 44-45; Metcalf, BPA, E-BPA-32, 43.

An NR-83 rate with an equalized demand charge and an energy charge equal to unit allocated energy costs would constitute an overall rate lower than the overall cost of exchange resources allocable to that rate class. Normally the equalization step would solve that problem by calculating the demand charge underrecovery of costs from the demand charge and adding that underrecovery to the costs to be recovered from the energy charge. This methodology does not work for the NR-83 rate because there are no demand costs allocated to NR.

BPA's method resulted in an NR-83 rate with energy charges and equalized demand charges based on exchange demand and energy costs. Thus, while the rate does not collect the allocated costs, it is based on the cost of the resources (exchange) available to serve the class. Metcalf, BPA, E-BPA-32, 43.

The ICP also objected to paying for a demand charge even if no on-peak service were taken, and to an NR rate higher than the SP rate. Lauckhart, ICP, E-IC-02, 4-6; Opening Brief, PSP&L, B-PS-01, 5. The former problem has been alleviated by changing the billing determinants for contracted computed requirements customers to be the same as those for planned and actual computed requirements customers. The latter problem has been resolved because of a slight change in the conservation allocation methodology.

Decision

As in the initial proposal, the NR-83 rate has been designed with an equalized demand charge and energy charge so that, combined, these charges will recover exchange costs. This rate is based on cost of service and is the rate which would have resulted from the cost allocation process if there had been both energy and demand loads forecasted for the class. The billing determinants for contracted computed requirements customers have been changed so that no demand charge will be paid if no service is taken over peak hours.

8. Surplus Firm Power Rate, SP-83

The Surplus Firm Power rate, SP-83, is applicable to sales of BPA's surplus firm power under either short-term or long-term contracts.

Issue #1

Have resource costs been properly allocated to the SP rate schedule?

Summary of Positions

In BPA's initial proposal the SP-83 Contract rate was based on the fully allocated cost of surplus resources; i.e., exchange resources and new resources. BPA, E-BPA-7, 46; Metcalf, BPA, E-BPA-32, 46.

LADWP argued in its prefiled testimony that at least part of the cost of new resources should be borne by PF customers. Further, LADWP contends that costs which do not contribute to the availability of SP power (deferral, Hanna, DSI reserves) should be excluded from the rate schedule. Parmesano, LADWP, E-LA-1, 10.

The California PUC also believes that the cost of projects being constructed to serve Pacific Northwest loads should not be recovered through sales outside the Region. The rate instead should be based on the variable cost incurred in providing the SP service, plus some small premium. Mattson, CPUC, E-CP-1, 9-10; Opening Brief, CPUC, B-CP-01, 16-17; Reply Brief, CPUC, R-CP-01, 15.

Evaluation of Positions

Section 5(f) of the Regional Act authorizes the Administrator to sell electric power that is surplus to BPA's firm power obligations in the Region. 16 U.S.C. §839c (f) (Supp. V 1981). Sound business principles govern the establishment of surplus firm power rates, in accordance with section 7(a) of the Regional Act, sections 9 and 10 of the Transmission System Act, and section 5 of the Flood Control Act. In addition, revenues from the sale of surplus firm power must contribute to meeting BPA's obligations to repay the U.S. Treasury and recover total system costs.

Therefore, BPA's surplus firm power rates recover the costs of resources not allocated to priority firm, industrial firm, and new resources customers. If BPA allocated to surplus firm power sales less than its remaining costs, BPA's rates would not be set at a level sufficient to recover the Administrator's total system costs.

LADWP believes that BPA's PF customers should help pay for new resources since the resources are acquired for and will benefit the Northwest customers in the long run. Parmesano, LADWP, E-LA-01, 10. However, it is not unusual in the resource-pool/load-pool ratemaking methodology prescribed by the Regional Act for a resource to shift from one pool to another. Nevertheless, the cost allocations must be based on the current load/resource balance. Discussions of which resources (and associated costs) are "really" used to serve a particular load are fruitless as they do not lend to formulation of standards appropriate to establishing surplus firm power rates.

LADWP asserts that costs associated with the deferral, Hanna, and reserves provided by the DSI's should be excluded from the SP-83 rate schedule. Parmesano, LADWP, E-LA-1, 10. However, as noted above, the SP rate is based on the cost of the firm resources not required to meet BPA's other firm loads. As such, all costs associated with these resources should be reflected in the development of the rate.

The CPUC argues that exchange resources and new resources are acquired to meet Pacific Northwest loads and that these resources should not be considered surplus. They point out that it is impossible to have surplus exchange resources since the exchange load exactly equals the exchange resource. Mattson, CPUC, E-CP-1, 10. However, the CPUC overlooks the fact that for ratemaking purposes the exchange resource is not used to serve the exchange load. Based on Regional Act service priorities, BPA allocates its resources to load in particular ways. Thus, the surplus may indeed be composed of exchange or new resources even if those resources were originally acquired in order to serve Pacific Northwest loads.

The CPUC's argument that the Surplus Firm Power rate be based on variable resource costs plus an adder is not persuasive, because BPA's other firm power rates are based on average embedded cost of service.

Decision

It is appropriate for BPA's surplus firm power rates to recover the cost of resources not allocated to other firm classes of service and surplus to BPA's firm power obligations. These resources and associated costs are exchange resources and new resources.

Issue #2

Does BPA's proposed SP rate schedule facilitate marketing BPA's surplus firm power?

Summary of Positions

BPA proposed that surplus firm power be sold under four different rates, a Contract rate, a Thermal Resource rate, an Exchange Resource rate, and a Purchased Power rate. BPA, E-BPA-7, 46; Metcalf, BPA, E-BPA-32, 45. Short-term sales (contracts of less than one year and terminating before June 30, 1985) may be made at any of the four rates. Contracts of more than one year or terminating after June 30, 1985, would reference the Contract rate. The Exchange Adjustment Clause was included in the SP-83 rates, but BPA indicated that it was considering removing the clause in order to enhance marketablity of the power.

The Contract rate would be based on the fully allocated cost of exchange resources and new resources. Beginning July 1, 1985, an escalation factor would be applied to the Contract rate on a yearly basis to account for changes in the cost of exchange resources. The Contract rate has a seasonally and diurnally differentiated demand charge, and a seasonally differentiated energy charge.

The three short-term rates would be based on the cost to BPA of acquiring and marketing the resource, though the Thermal Resource rate may exclude some fixed costs. BPA, E-BPA-7, 46; Metcalf, BPA, E-BPA-32, 45, 47; Metcalf, BPA, TR 5448-5449.

The DSI's suggested that the Thermal Resource rate, Exchange Resource rate, and Contract rate be combined. This combined rate should have a single on-peak demand charge and a single energy charge with the option of melding capacity and energy charges into a single energy charge. If unsold surplus remains, BPA should offer power for periods of less than a year and as short as 7 days. These offers "might be structured in a variety of ways depending on...the requirements of the California utilities." Mizer, DSI, E-DS-13, 8-12; Opening Brief, DSI, B-DS-01, 17. The PPC supports many of the DSI positions, though not elimination of seasonal differentiation. Opening Brief, PPC, B-PP-01, 25; Reply Brief, PPC, R-PP-01, 15.

The IPUC believes that effective marketing of surplus power outside the region depends on offering long term contracts at an attractive price "which is reasonably predictable to the purchaser." The price "should not be lower than the variable costs of operating thermal resources within the region. That is, it must pay for at least some of the fixed costs of thermal plants." Reading, IPUC, E-IP-01, 4.

The CPUC supports allowing purchasers of SP power to substitute purchases of NF when this option is available. Mattson, CPUC, E-CP-01, 26; Opening Brief, CPUC, B-CP-01, 17.

Evaluation of Positions

The DSI's propose eliminating the seasonal differentiation from the SP-83 rate because "by definition, capacity and energy sold under the SP-83 rate are surplus to the requirements of the Pacific Northwest. There is, therefore, no reason to be concerned with price signals in marketing surplus firm power." Mizer, DSI, E-DS-13, 10. In addition, elimination of seasonal differentiation of the rates may result in greater revenue recovery since the Pacific Southwest customers face their highest operating costs during the summer months. Mizer, BPA, E-DS-13, 11.

The DSI's and PPC also propose eliminating the variable nature of the Thermal and Exchange rates, but give no explanation of how BPA can compete for sales in the short-term market with a fixed rate. Mizer, DSI, E-DS-13, 12; Opening Brief, DSI, B-DS-01, 17; Opening Brief, PPC, B-PP-01, 25.

The IPUC appears to endorse BPA's proposed rate. Reading, IPUC, E-IP-01. BPA's Contract rate includes an escalation clause which remains fixed (with respect to how the escalation factor is calculated) over the life of the contract. BPA, E-BPA-7, Appendix C, C-62-63. The Thermal Resource rate is quite close in structure to that proposed by IPUC.

The CPUC recommendation that surplus sales be displaceable by nonfirm purchases is more properly handled in the contract. Mattson, CPUC, E-CP-01, 26. The proposed SP-83 rate schedule does not preclude such an arrangement.

Decision

The seasonal differentiation in the Surplus Firm Power rate has been eliminated in order to improve the marketability of the surplus, as the DSI's suggested. The variable nature of the Thermal and Exchange rates has been retained in order to encourage short-term marketing in a competitive market.

Issue #3

How should the escalation factor in the Contract rate be structured?

Summary of Positions

BPA has proposed an escalation factor to account for cost increases in contracts that extend past June 30, 1985. The escalation factor will be "the percentage increase in the average cost of selected exchange resources" in the prior year and is "based on the exchange resources of IOU's whose average system costs are forecasted to be greater than the Priority Firm rate." BPA, E-BPA-7, 47; Metcalf, BPA, E-BPA-32, 46.

CPUC proposed an alternative escalation factor based on the "variable operating costs of Pacific Northwest coal plants." Mattson, CPUC, E-CP-01, 29.

The CEC proposed a "cap" on the escalation factor. This cap could be based on some indicator of general inflation, Northwest coal costs, or some other factor. Opening Brief, CEC, B-CC-01, 28; Reply Brief, CEC, R-CC-01, 9.

Evaluation of Positions

The CPUC proposed an escalation factor based on variable coal plant costs because it is these resources that are "used to serve SP sales." Mattson, CPUC, E-CP-01, 29. No evidence was given that coal plants are used to serve SP sales. Further, BPA is not forecasted to have any power from coal plants during the rate period. The load-pool and resource-pool methodology prescribed by the Regional Act results in the surplus being served (for ratemaking purposes) by exchange resources and new resources. The vast majority of surplus resources is based on exchange resources and the nondeemer IOU's contribute the majority of the net cost of the exchange which BPA actually pays. Metcalf, BPA, E-BPA-32, 46-47. Therefore, the growth in average system costs of the non-deemer IOU's will closely reflect BPA's surplus resource costs.

The CEC proposed a "cap" on the escalation factor to make the rate more predictable over time. They contend that a utility may be reluctant to enter into a long-term contract for purchase of surplus firm power if the utility is unable to predict with some degree of certainty what the rate will be from year to year. Opening Brief, CEC, B-CC-01, 26-29. As evidence of the unpredictability of the proposed escalation factor, the CEC contends that a potential purchaser must "speculate as to the future behavior of three very uncertain factors, all outside the purchaser's control." These uncertain factors are (1) BPA priority firm rates; (2) composition of IOU non-deemers; and (3) the average system cost of the non-deemers. Opening Brief, CEC, B-CC-01, 27. BPA witnesses have testified to the uncertainty of projecting exchange costs. Meyer, BPA, E-BPA-23, 3; Metcalf, BPA, TR 5530-5531.

To be of potential benefit to a purchaser of surplus firm power, however, CEC's proposed cap should have certain features. At a minimum, the cap should be (1) more predictable than the proposed escalation factor; and (2) not be set so high as to be meaningless. BPA agrees that a cap based on general inflation, Northwest coal costs, or some other generally recognized factor might be more predictable, and therefore, more attractive to a purchaser than the proposed escalation factor. Carr, BPA, TR 5533. However, a cap based on these or similar factors may be insufficient to recover increased SP costs. The risk of revenue underrecovery increases as the cap is lowered.

A purchaser of surplus firm power under the CEC's proposed cap would pay actual increased resource costs unless these costs exceed the cap. Thus, there is an obvious bias toward underrecovery of costs, and the risk of underrecovery is borne entirely by BPA.

A "fixed" escalation factor is superior to the CEC proposal. A fixed escalator would be predictable, thus satisfying a major CEC criterion. The risk of underrecovery would, however, be shared by the purchasers and BPA. The possiblity of revenue underrecovery for a particular year would still exist, though this shortfall might be compensated by overrecovery in another year. Over the duration of the contract, there would be a possibility of either revenue over or underrecovery. This condition is preferable to the one-way risk of a "cap." The fixed escalator ideally should leave BPA no worse off over the length of the contract than if BPA could collect the actual year-by-year resource cost increases. Since there is a risk of underrecovery, however, this risk should be accounted for in establishing the fixed escalator.

Decision

The escalation factor will continue to adjust the SP rate yearly. The adjustment will be based on the average cost of selected exchange resources as outlined in the initial proposal.

Additionally, a purchaser of surplus firm power may select an alternative fixed escalator option. The fixed option is offered in response to the CEC's recommendation that greater predictability of the escalator will help in marketing under the SP-83 rate schedule.

The fixed option is offered to give a prospective purchaser price certainty. The fixed escalator was calculated from BPA's forecast of the SP rate through 1991. The forecast is based on high load forecasts and rates of inflation in order to reflect the increased risk taken by BPA in offering this option.

Issue #4

Should surplus firm power be allowed to be sold at a level below the Nonfirm Energy Standard rate?

Summary of Positions

BPA's initial proposal does not specify a lower limit for the SP-83 variable rates. BPA, E-BPA-07, 45-47.

The NWU's noted this lack of a rate floor and proposed that "Bonneville should not provide for the sale of firm power for less than the nonfirm Standard Rate." Schultz, NWU, E-NW-07, 9. This position was supported by the PPC. Opening Brief, PPC, B-PP-01, 25.

Evaluation of Positions

NWU seems to be concerned with pricing discontinuity and potential marketing problems that may result. Perhaps, and more importantly, NWU is concerned that higher quality power should be sold at a premium price. The PPC, in recommending a single charge that melds the Thermal Resource rate and the Exchange Resource rate, state that this charge "should always exceed the NF standard rate by an amount sufficient to reflect the quality of power provided." Opening Brief, PPC, B-PP-01, 25.

On the other hand, setting a rate floor for the SP-83 variable rates will reduce some of the flexibility intended for these rates to encourage short-term marketing in a competitive market. For example, when Spill rate energy is available, BPA may wish to market SP-83 power at a rate lower than the NF-83 Standard rate but higher than the guaranteed Spill rate.

Decision

The variable nature of the Thermal Resource rate and Exchange Resource rate has been retained. Stipulating a SP-83 rate floor would unnecessarily reduce BPA's marketing flexibility.

9. Surplus Firm Energy Rate, SE-83

The SE-83 rate is available for sales of BPA's surplus firm energy. Issues related to this rate schedule were addressed as part of the SP-83 discussion.

The major changes to the SP-83 rate schedule from the Initial Proposal are:

a. Reference to the interruptibility of energy delivery has been deleted. Metcalf, BPA, TR 5523, 7272.

b. The Exchange Adjustment Clause will not be included in the SE-83 rate schedule. Metcalf, BPA, E-BPA-32, 29. Metcalf, BPA, TR 7257-7258.

c. An escalation factor has been added to account for changes in the cost of exchange resources for contracts that extend past June 30, 1985. The escalation factor provisions are identical to those applicable to the SP-83 rate schedule. Metcalf, BPA, TR 5530.

10. Nonfirm Energy Rate, NF-83

The NF-83 rate is applied to purchases of nonfirm energy. The initial proposal includes a Contract rate and four market rates: the Standard rate, the Spill rate, the Displacement rate, and the Incremental rate. BPA also discussed an alternative NF rate schedule in which the Spill rate would be eliminated. Issues related to the NF-83 rate are discussed below.

a. Compliance with Statutory Standards

Issue #1

Does the NF-83 rate comply with all applicable statutory standards?

Summary of Positions

SCE, LADWP, and PG&E argue that the statutory standards applicable to BPA require BPA's rates to be based on cost of service. Opening Brief, SCE, B-CE-01, 16; Opening Brief, LA/PG&E, B-LA/GA-01, 23. These parties also argue that BPA's nonfirm rates are inconsistent with the statutory standard that BPA's rates should be the lowest possible consistent with sound business principles. Opening Brief, SCE, B-CE-01, 16; Opening Brief, LA/PG&E, B-LA/GA-01, 24. The DSI's disagree with this argument, stating that if any one rate schedule has claim to being the lowest possible, this assures that all other rates will not be as low as possible. Opening Brief, DSI, B-DS-01, 88. SCE and PG&E argue that the legislative history of section 7(k) of the Regional Act supports the proposition that 7(k) was intended to prevent BPA from charging noncost-based rates to non-Regional customers. Opening Brief, SCE, B-CE-01, 16; Pretrial Brief, PG&E, 7-8.

Evaluation of Positions

As discussed below, BPA disagrees with the argument proffered by SCE, that statutory standards require BPA's rates to be based on cost of service. BPA believes that the applicable statutes allow the Administrator discretion with respect to rate form and design. Notwithstanding this option to base rates on other than cost of service, BPA has continued to base its Nonfirm Energy rate, to the maximum extent practicable, on the cost of providing nonfirm service. Hence, the arguments made by the California parties that the Administrator is required to base rates on cost of service, are rendered moot.

The statutory standards applicable to BPA's rates, which are referred to by the California parties, are found in the following: section 7(a)(1) of the Regional Act, 16 U.S.C. §839e(a)(1) ("sound business principles"); section 7(k) of the Regional Act, 16 U.S.C. §839e(k) ("in accordance with the Bonneville Project Act, the Flood Control Act of 1944, and the Federal Columbia River Transmission System Act."); section 9 of the Federal Columbia River Transmission System Act, 16 U.S.C. §838g ("with a view towards encouraging the widest possible diversified use of electric power" and "lowest possible rates to consumers consistent with sound business principles"); sections 6 and 7 of the Bonneville Project Act, 16 U.S.C. §§832e and f ("with a view to encouraging the widest possible use of electric energy"); section 5 of the Flood Control Act of 1944, 16 U.S.C. §825s ("in such a manner as to encourage the most widespread use thereof," "lowest possible rates to consumers consistent with sound business principles," and "sale on fair and reasonable terms and conditions"). These statutory standards do not expressly require cost-of-service based rates, nor can such requirement be implied.

The legislative history of the Bonneville Project Act is replete with discussion of Congressional concern that the Federal investment be repaid, but noticeably devoid of reference to any particular cost of service methods or rate design. Indeed, a sponsor of the bill stated that "[i]t has long been a congressional policy not to express an exact or fixed rate formula in any bill, but to control and check by regulation." Columbia River (Bonneville Dam) Oregon and Washington Hearings on H.R. 7642 before the House Committee on Rivers and Harbors, 75th Cong. 1st Sess. 181 (1937). The plain words of the statutes and the legislative history subsequent to the Bonneville Project Act indicate that the new statutes did not provide new standards for review, but simply reiterated existing standards. Regarding the Transmission System Act, see H. Rep. No. 1375, 93rd Cong., 2d Sess. 5 (1974); regarding the Regional Act, see section 7(a)(1), see S. Rep. No. 272. 96th Cong., 1st Sess. 31 (1979) and H. Rep. No. 976, Part II, 96th Cong., 2d Sess. 52 (1980); regarding Regional Act Section 7(k), see H. Rep. No. 976, Part I, 96th Cong., 2d Sess. 70 (1980) and H. Rep. no. 976, Part II, 96th Cong., 2d Sess. 53 (1980).

The argument proffered by the California parties that the statutory standards cited above require the Administrator to base rates on cost of service, was expressly rejected in Pacific Power & Light Co. v. Duncan, 499 F. Supp. 672, 682 (D. Or. 1980). In addition, the court held that these statutes granted the Administrator such broad discretion that judicial review is precluded because there is no law to apply. Id. at 682. Cf City of Santa Clara v. Andrus, 572 F.2d 660, 668 (9th Cir. 1978) (Flood Control Act of 1944 provides no law to apply).

In addition to those standards quoted above, each of these statutes contains standards which direct BPA to set rates which are sufficient to cumulatively recover the Federal debt plus other costs. For example, the Regional Act provides that rates shall be set to recover "the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this act and other provisions of the law." 16 U.S.C. §839e(a)(1). Similarly, the Bonneville Project Act requires that BPA's rates recover "the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years." 16 U.S.C. §832f. Construing the standards quoted in the prior paragraphs together with these standards relating to revenue sufficiency leads to the conclusion that BPA's rates overall should be as low as possible consistent with sound business principles so long as they are cumulatively high enough to recover the Federal debt plus other costs, while encouraging the widest possible use and providing for sales on fair and reasonable terms. The NF-83 schedule, taken together with all of the other rate schedules proposed in this case, meets these statutory tests.

Evidence that BPA's rates are as low as possible is found throughout the record, particularly in the WPRDS. See, for example, the Low Density Discount and the Special Industrial rate. Evidence that the rates are high enough to recover the Federal investment is contained in the Revenue Forecast Study and the Revenue Requirement Study, as well as in other parts of the record. Evidence that the rates comport with sound business principles can be found throughout the record, including the WPRDS. The NF-83 rate is a particularly good example. The design of NF-83 Spill and Displacement rates below the level of the cost-based Standard rate is grounded in prudent utility practice and sound business principles. These rates are designed to respond to market conditions which disallow the marketing of all nonfirm energy at cost. These rates are designed to maximize sales and revenues, discourage spill, and displace oil, gas, coal and nuclear generation whenever possible. Evidence that BPA's rates encourage the widespread use of electricity is also contained throughout the record, particulary in the WPRDS. For example, the NF-83 Displacement rate is designed to encourage the displacement of a variety of generation resources in the Region and outside the Region. Finally, evidence that BPA's rates provide for sales on terms and conditions which are fair and reasonable is found in the rate schedules and the general rate schedule provisions incorporated therein.

The California parties argue that the NF-83 rate is unlawful because it is not the "lowest possible rate" as provided for in applicable statutes. This argument does not withstand scrutiny. As the DSI's point out in their brief, it is illogical to attempt to apply the "lowest possible rates" standard to any one particular rate schedule. Opening Brief, DSI, B-DS-01, 88. To lower the NF-83 rate to the lowest possible level necessitates raising other rates. Customers purchasing under other schedules can, in turn, argue that the schedule they are purchasing under is not the "lowest possible rate." As discussed above, the "lowest possible rates" standard applies to all of BPA's rate schedules taken together, not to individual rate schedules considered separately.

PG&E's argument that the legislative history of section 7(k) of the Regional Act supports the proposition that 7(k) was intended to prevent BPA from charging non-cost-based rates to non-Regional customers is without merit. Section 7(k) provides that rates for the sale of nonfirm energy outside the Region shall be in accord with the Bonneville Project Act, the Flood Control Act of 1944, and the Federal Columbia River Transmission System Act. 16 U.S.C. §839e(k). Section 7(k) does not alter or supplement the standards already contained in these three statutes. It simply reiterates their applicability. There is no need to resort to an examination of legislative history of 7(k), since its meaning is unambiguous. The proper function of legislative history is to solve, not to create, an ambiguity. U.S. v. Richards, 583 F.2d 491. 495 (9th Cir. 1978); U.S. v. Blasius, 397 F.2d 203 (2nd Cir. 1968), cert. denied, 393 U.S. 1008. As discussed above, the standards contained in the Bonneville Project Act, the Flood Control Act of 1944, and the Federal Columbia Transmission System Act do not impose upon BPA a cost-of-service ratemaking standard.

Decision

BPA's NF-83 rate complies with all applicable statutory standards.

b. Compliance With PURPA Cost of Service Standard

Issue #1

Does the NF-83 rate comply with the standard adopted by BPA pursuant to the Public Utility Regulatory Policies Act of 1978?

Summary of Positions

SCE and LADWP argue that BPA has violated the standard it adopted pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.S. §2601 et seq. Opening Brief, SCE, B-CE-01, 17; Trial Brief, LADWP, 5. SCE and LADWP argue that BPA adopted a cost-of-service ratemaking standard in adopting a regulation pursuant to PURPA, and that the proposed NF-83 rate violates that standard because it is not based on cost of service.

Evaluation of Positions

BPA disagrees with this argument on two grounds. First, the regulation promulgated by BPA pursuant to PURPA allows the Administrator continued discretion with respect to rate form and design. Second, notwithstanding that it was not required to do so, BPA has proposed an NF-83 rate which is based, to the maximum extent practicable, on the cost of providing nonfirm service. Hence, the arguments of the California parties are rendered moot.

Reference to the complete text of the standard adopted by BPA makes clear the degree of discretion allowed:

> COST OF SERVICE--Rates charged by Bonneville for providing electric service to each class of its customers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class. The costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of reasonable, accepted accounting methods. Such methods shall to the extent practicable permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, Bonneville will use embedded and long-run incremental costs. The rate design will always consider such an embedded cost-of-service analysis but will also consider other factors, such as marginal or long-run incremental cost principles, the purposes of conservation, efficient use of resources, and equity, and the need to meet legal considerations.

This regulation was promulgated pursuant to Section 111 of PURPA, which requires only the consideration of specified rate standards in order to "make a determination whether or not it is appropriate to implement such standard . . . ." 16 U.S.C. §2621(a).

As discussed elsewhere, BPA based its NF-83 Standard rate on the average cost of service of loads served with FBS and new resources power, the two resource pools which produce nonfirm energy. Hence, consistent with BPA's PURPA standard, the NF-83 Standard rate has been designed "to reflect the costs of providing electric service to such class." Also consistent with the PURPA standard, BPA has based the NF-83 Standard rate on the embedded costs of its system. As discussed elsewhere, the NF-83 Spill and Displacement rates are set at a level below the Standard rate, because market conditions dictate that it is not "practicable" for BPA to sell all of its nonfirm energy at cost. BPA's departure from a cost of service based rate is plainly contemplated by its PURPA standard.

Decision

BPA's NF-83 rate complies fully with the standard adopted by BPA pursuant to PURPA.

c. Standard Rate

Issue #1

What is the appropriate general methodology for setting the Standard rate?

Summary of Positions

In BPA's initial proposal, the Standard rate is equal to the average cost of the FBS and new resource pools, plus the average cost of transmitting such power. The rate is calculated by: (1) summing FBS resource costs, new resource costs, and costs allocated to loads served with FBS and new resources (other generation costs, reserve credit and FCRTS costs); (2) subtracting NF-83 Spill rate revenue from the amount calculated in (1); and (3) dividing the amount determined in (2) by the sum of forecast firm load, DSI first quartile sales, and NF-83 Standard rate sales. Metcalf, BPA, E-BPA-32, 51.

The California parties (LADWP, PG&E, SCE, and CPUC) object to the level of the Standard rate and the costs included in its calculation. LADWP argues that the Standard rate is not based on cost to the maximum extent practicable and is not justified on the basis of BPA's cost of supplying nonfirm energy. Parmesano, LADWP, E-LA-01, 1-2, 7. SCE contends that because the Standard rate is higher than the rate recommended by SCE, the Standard rate (1) discriminates against purchasers since it exceeds properly assignable costs; and (2) is inconsistent with the requirement of encouraging the widest possible diversified use of electric energy at the lowest possible rate, consistent with sound business principles. Lindsay, SCE, E-CE-01, 5.

LADWP, SCE, SDG&E, and CPUC state that the Standard rate should be no higher than the energy portion of the PF rate, since they assume that the cost of providing nonfirm energy is less than the cost of providing firm energy. Parmesano, LADWP, E-LA-01, 8; Lindsay, SCE, E-CE-01, 5; Reply Brief, SCE, E-CE-01, 31-32; Reply Brief, SDG&E, R-SD-01, 4; Mattson, CPUC, E-CP-01, 20.

The NWU's and DSI's support BPA's proposal to base the Standard rate on total system costs. Schultz, NWU, E-NW-25R, 1-2; Mizer, DSI, E-DS-13, 16-17.

Although the PGP prefers a share-the-savings nonfirm rate, they also support a Standard Rate based on total system costs if BPA chooses to implement a Standard rate. Garman, et al., PGP, E-PG-06R, 17.

Evaluation of Positions

BPA set the Standard rate at the average cost of generating and transmitting FBS and new resource power, because those are the resource pools which contribute to the availability of nonfirm energy. Metcalf, BPA, TR 5482-5484.

LADWP asserts that BPA has given insufficient attention to the goal of basing rates on cost to the maximum extent possible, an objective identified in standard ratemaking textbooks as well as in the Public Utility Regulatory Policies Act of 1978 (PURPA) (see discussion in section (1) concerning compliance with the PURPA standard and section (5) concerning Bonbright's text). Parmesano, LADWP, E-LA-01, 1-2; Parmesano, LADWP, E-LA-04R, 1-4.

It is true that the NF-83 rate is forecast to recover revenues greater than the costs allocated to that class in the COSA. That is because the COSA is designed to allocate costs from three resource pools under an assumption of critical water. BPA, E-BPA-5, 7. This assumption reflects a resource planning criterion of the Region. However, rates are designed based on an average water assumption. This rate design assumption recognizes that BPA will usually have the ability to generate more power than the critical water assumption accounts for, as well as the role that the nonfirm energy market plays in resource planning decisions. NWU's discuss this latter point in responding to CPUC's contention that the Pacific Northwest is responsible for all of BPA's costs because BPA resources are provided for Pacific Northwest customers. The NWU's argue that the economic trade-offs of potential uses of nonfirm energy have a significant bearing on the mix of new resources selected, the type of load to be encouraged, and reservoir management strategies. Schultz, NWU, E-NW-25R, 2.

The NWU's argue that if a low price were received for nonfirm energy, the region would tend to develop resources with low capital costs and high production costs. A low nonfirm energy price also would encourage development of additional interruptible loads in the region. The region would tend to develop baseload resources if it received a higher price for nonfirm. A higher price would encourage Pacific Northwest utilities to make more nonfirm energy available through more agressive use of reservoir storage earlier in the operating year; that is, greater risks would be taken for higher pay-offs. "Although the market for nonfirm energy does not affect the amount of resource acquired, it is a crucial determinant of the types of resources selected. The choice of high-capital-cost/low-production-cost resources have been made consciously, in the expectation of nonfirm energy revenues recovering a portion of fixed costs. The high fixed costs were incurred in order to enable production at low variable costs; the combination properly reflects, I believe, the cost of nonfirm energy." Schultz, NWU, E-NW-25R, 2-4. Therefore, BPA's average system cost is the appropriate cost-based nonfirm rate. On a planning basis, nonfirm markets influence the generation mix, and on an operational basis it is very difficult to identify the particular resource being sold in a hydro-storage-thermal system.

The CPUC disagrees that the choice of resources is based on expectations regarding the possible market for nonfirm energy. Instead they assert that the objective is the minimization of the Region's total costs. Therefore, they argue that the cost of nonfirm service is related only to the variable cost of providing that service. Reply Brief, CPUC, R-CP-01, 5-6.

The CPUC is incorrect that minimization of total cost is the criteria to be used in the choice of resources. A mix of resources which produces a large amount of nonfirm energy may be preferable to a lower cost mix of resources which produces little or no nonfirm energy. The CPUC proposes to base all BPA rates on marginal costs. Reply Brief, CPUC, R-CP-01, 10-15. However, BPA's current short run marginal cost of providing all services is very low, and rates based on such costs would fall far short of BPA's revenue requirement. The CPUC offers no methodology for inflating short run marginal cost rates to recover that requirement.

PG&E argues that the use of total system costs is inappropriate for the design of the Standard rate because BPA does not plan to assure a supply of nonfirm energy. Reply Brief, PG&E, R-GA-01, 18. While it is true that firm resources are not built for nonfirm service, the mix of such resources is influenced by that market, and the amount of nonfirm energy from any particular mix can be forecasted on a statistical basis.

The California parties propose various alternative Standard rates that are all less than the BPA proposal. SCE and LADWP argue that nonfirm energy sales would materially increase if lower rates were charged and the increased sales would substantially offset any loss in revenue. Parmesano, LADWP, TR 7078; Lindsay, SCE, E-CE-01, 4-5. However, California parties did not perform any studies to give credence to their assertion. Parmesano, LADWP, TR 7077-7078; Mattson, CPUC, TR 7245-7246. BPA analyzed each California NF-83 rate alternative. The results of the analyses were that revenues from nonfirm energy sales under each California proposal would be ". . . substantially less than they would be if the Nonfirm Energy rate contained in Mr. Metcalf's supplemental testimony, Exhibit BPA-32S, was adopted." Wedlund, BPA, E-BPA-48R, 3.

LADWP, SCE, and CPUC state that the Standard rate should be no higher than the energy portion of the PF rate. This is based on the assumption that the cost of providing nonfirm energy is less than the cost of providing firm energy. Parmesano, LADWP, E-LA-01, 8; Lindsay, SCE, E-CE-01, 5; Reply Brief, SCE, R-CE-01, 31-32; Reply Brief, SCE, R-CE-01, 31-32; Mattson, CPUC, E-CP-01, 20. LADWP recommends that the energy portion of the PF rate be used as a proxy for setting the Standard rate for nonguaranteed energy. However, there appears to be little basis for comparability between the NF-83 rate which is based on costs of FBS and new resources and the PF rate which is based on costs of FBS and exchange resources. There are also other firm power rates (NR-83 and SP-83) that could be used as well. LADWP responds that use of a sales weighted average of firm energy rates would be even better than use of the PF rate. Reply Brief, LADWP, R-LA-01, 9. Even if it were appropriate to compare the PF rate or all firm rates to the NF rate, the correct comparison would be the average PF rate or average firm rate to the average NF rate. The average NF rate has been consistently lower than the average PF rate and is forecast to be much lower during the upcoming rate period. In fact, the proposed Standard rate (guaranteed) of 20.3 mills/kWh is lower than the forecasted average Priority Firm rate, 22 mills/kWh.

Decision

The Standard rate has been designed to reflect total system costs because the total system contributes to the availability of nonfirm energy.

Issue #2

What specific cost components are appropriate for inclusion in the Standard Rate?

Summary of Positions

In BPA's initial proposal, the Standard rate is equal to the average cost of the FBS and new resource pools, plus the average cost of transmitting such power. The rate is calculated by: (1) summing FBS resource costs, new resource costs, and costs allocated to loads served with FBS and new resources (other generation costs, reserve credit and FCRTS costs); (2) subtracting NF-83 Spill rate revenue from the amount calculated in (1); and (3) dividing the amount determined in (2) by the sum of forecast firm load, DSI first quartile sales, and NF-83 Standard rate sales.

Inclusion of capacity costs in the Standard rate were objected to by all California parties, and inclusion of costs of Supply System plants 1 and 3, industrial reserves, deferral, Pacific Northwest transmission segments, and Capacity/Energy Exchange were objected to by one or more California parties. Parmesano, LADWP, E-LA-01, 7; Buckingham, PG&E, E-GA-01, 3, 6-8; Lindsay, SCE, E-CE-01, 3-4; Mattson, CPUC, E-CP-01, 8-9, 17-18; Reply Brief, CPUC, R-CP-01, 6; Reply Brief, SDG&E, R-SD-01, 4. LADWP also argues that excess revenues from the NF-83 Displacement, Incremental, and Contract rates and from the Energy Broker rate should be deducted in calculating the Standard rate. Parmesano, LADWP, E-LA-01, 7-8.

The NWU's support BPA's method of determining the Standard rate. Schultz, NWU, E-NW-25R, 1-2. Although the PGP supports a share-the-savings nonfirm energy rate, they offer two recommendations for a Standard rate if included in BPA's final proposal: first, that sales of nonfirm and revenues therefrom be eliminated from the Standard rate calculation, and second, that all costs that contribute to the supply of nonfirm energy be included in the calculation, such as current and future plant, conservation and exchange resource costs. Garman, et al., PGP, E-PG-06R, 17.

The DSI NF-83 proposal includes a fixed rate that is roughly equivalent to the Standard rate. This fixed rate would be equal to the average total cost of the BPA's system (including exchange resources), plus a transmission component for export sales. In addition, this rate would be time differentiated. Mizer, DSI, E-DS-13, 16-17.

Evaluation of Positions

Capacity Costs

All California parties objected to the inclusion of capacity costs in the Standard rate. LADWP states that there is no cost justification for including capacity costs in the Standard rate unless a 5-day guarantee is offered in a nondiscriminatory manner. Parmesano, LADWP, E-LA-01, 9. PG&E and SCE assert that purchasers receive little or no capacity benefit from purchases of nonfirm energy and, thus, capacity costs should not be included in the Standard rate. CPUC contends that BPA should seek to recover fixed costs only from those customers for whom capacity is installed. Reply Brief, CPUC, R-CP-01, 6.

Generation capacity costs are properly included in the Standard rate. California parties confuse firm service (guarantee of delivery when needed) with capacity service (delivery during peak periods). In a thermal system, these two concepts are similar because the system is normally capacity constrained. In a large hydro storage system, delivery of nonfirm energy is usually energy constrained, not capacity constrained. BPA classifies a majority of its hydrogeneration costs to capacity so exclusion of hydro capacity costs from the Standard rate would result in nonfirm energy purchasers sharing in the recovery of only a small component of hydro costs. The capacity of the hydro system, including peaking units, is necessary to deliver nonfirm energy over peak hours. Inclusion of thermal capacity cost is a closer question. Thermal capacity is less clearly used to deliver nonfirm energy than hydro capacity. Also, in contrast to hydrogeneration, which is primarily classified to capacity, thermal generation is classified primarily to energy according to the results of the TDLRIC Analysis. Thus, even if thermal capacity costs were excluded from the nonguaranteed Standard rate, those purchasers would share in paying for some of the fixed costs of those resources. Therefore, it would appear reasonable to include thermal generation capacity costs in the guaranteed Standard rate but not the non-guaranteed Standard rate.

SCE and LADWP respond that they do not confuse firm service with capacity service, but that both services require the seller to maintain sufficient capacity to meet its obligation. Reply Brief, SCE, R-CE-01, 30; Reply Brief, LADWP, R-LA-01, 12. However, the implication that capacity service must be firm is incorrect, as evidenced by BPA's Emergency Capacity rate schedule for the sale of nonfirm capacity. Using LADWP's reasoning, BPA could not charge for that service because neither energy or capacity costs could be included in the rate.

Supply System Costs

With regard to the Supply System costs, California parties make two arguments for excluding those costs. First, they argue that the incurrence of cost of those plants was not caused by nonfirm energy users. Parmesano, LADWP, E-LA-01, 7; Lindsay, SCE, E-CE-01, 3-4; Mattson, CPUC, E-CP-01, 8-9; Reply Brief, CPUC, R-CP-01, 6-7.

The NWU's respond to the California arguments that Supply System costs should not be included in the Standard rate. They argue that "it is almost impossible to determine, in a predominantly hydroelectric system with substantial seasonal storage, which facility is responsible for the production of a particular kilowatthour of nonfirm energy." Therefore, "the average system cost is a reasonable basis for the Standard rate because it is consistent with the position that FCRPS nonfirm energy is a function of the system, rather than any specific resource." Schultz, NWU, E-NW-25R, 1-2. The combined effect of thermal resources, hydro resources and substantial storage capability do not allow BPA to separately identify the specific resources responsible for the nonfirm energy. LADWP acceded to the possibility that spill energy may not be available without the operation of thermal resources. Parmesano, LADWP, TR 7088.

LADWP argues that BPA uses the wrong test with respect to the inclusion of costs in its nonfirm rate, that the appropriate test is "who caused this cost to be incurred?", rather than "does this item contribute to the availability of nonfirm energy?" Reply Brief, LADWP, R-LA-01, 12. However, the reason BPA uses the latter test is that, as demonstrated in the previous section, the nonfirm market influences the generation mix in a combined hydro-storage-thermal system. Therefore, it is appropriate that nonfirm customers share in the costs for all resources which contribute to the availability of nonfirm energy.

The second argument for excluding Supply System costs is that WPN-1 and WNP-3 will not be online during the rate period and therefore do not contribute to the availability of nonfirm energy. Mattson, CPUC, E-CP-01, 8-9. However, BPA is contractually required to pay certain Supply System costs before the plants come on-line. Metcalf, BPA, TR 5594. It is appropriate that these costs be paid by the same customer groups that would pay for them if they were on-line. It is not important to examine whether these plants contribute to the availablity of various kinds of power before they come on-line. When they do come on-line, nonfirm energy customers will be receiving the benefit of the additional supply of power they provide. As the NWU noted, nuclear plants contribute to nonfirm energy availability because of their high fixed cost/low variable cost nature. Nonfirm customers would not be paying the full cost of service if they avoid paying the costs until the plants become operational.

Transmission Costs

LADWP objects to the inclusion of the fringe and delivery transmission segment costs in the Standard rate since these segments are not used to deliver nonfirm energy to California customers. Parmesano, LADWP, E-LA-01, 7. The DSI's recommend that a transmission component should be applied only to export sales of nonfirm energy. Mizer, DSI, E-DS-13, 16-17. This recommendation ignores the use of the Federal transmission system by all nonfirm energy.

All segments of the transmission system support the delivery of nonfirm energy to the Pacific Northwest and Pacific Southwest. Therefore, costs of all segments used to serve loads with FBS and new resources power are included in the Standard rate. The resulting unit transmission component is the average cost of transmitting power to a load regardless of where the load is located. Whereas it would be possible to charge different nonfirm energy rates to different areas based on transmission segments used, it is also reasonable to meld those costs and charge an average cost rate to all users. SCE argues that Capacity/Energy Exchange cost is not a part of the cost of providing nonfirm energy service and should not be included as a cost of serving such customers. Lindsay, SCE, E-CE-01, 4. The Capacity/Energy exchange cost referred to is the FCRTS costs allocated to that class of service. These costs must be included for the Standard rate to reflect the average cost of FBS and new resources transmission service.

Nonfirm Energy Revenue

LADWP also recommends that excess revenues from all NF-83 rates and the EB-83 rate be deducted in calculating the Standard rate. This change would be consistent with the deduction of Spill rate revenues and sales in the Standard rate calculation. Parmesano, LADWP, E-LA-01, 7-8. The PGP, however, recommends excluding all NF-83 sales and revenue from the calculation. Garman, et al., PGP, E-PG-06R, 17. BPA made this adjustment in the Standard rate calculation in order to equitably share Spill rate revenues between Standard rate purchasers and firm power purchasers. Metcalf, BPA, E-BPA-32, 52; Metcalf, BPA, TR 5468. Since the PGP does not rebut this justification or offer any reason for their recommendation, there appears to be no reason to omit this adjustment. BPA made the adjustment with only Spill rate sales and revenues because they are the major category of excess revenue. Metcalf, BPA, TR 5469. In the initial proposal, Spill rate revenues total $133 million while Displacement rate and EB-83 revenues total $3.6 million. Metcalf, BPA, E-BPA-32S, Attachment 1, 3. However, since an inconsistency is created by not adjusting for all below-cost nonfirm sales and revenues, it would be appropriate to make the adjustment to include all NF-83 and EB-83 sales and revenues.

Deferral

Another cost that should be excluded, argue LADWP and CPUC, is deferral cost because nonfirm energy customers are not responsible for the deferral. They argue that this is because nonfirm energy customers have paid rates above the true cost of supplying nonfirm energy. Parmesano, LADWP, E-LA-01, 7; Mattson, CPUC, E-CP-01, 18. CPUC asserts that because nonfirm energy purchasers have, for the last several years, paid rates which have included fixed costs, these purchasers cannot be said to have contributed to the need for deferral. Reply Brief, CPUC, R-CP-01, 6. SCE also objects to the inclusion of deferral cost in the Standard rate calculation. Reply Brief, SCE, R-CE-01, 31.

BPA allocates the deferral across all of its firm sales because it is virtually impossible to identify which customer classes are responsible for the deferral. Revitch, BPA, E-BPA-28, 4-5. Even if it were feasible to identify the deferral with the rate schedules which caused the deferral, nonfirm energy customers would be responsible for a share of previous deferrals because the costs used to calculate the nonfirm energy rate have been greater than forecast and surplus firm power has been sold at nonfirm energy rates that are far below the allocated cost.

Industrial Reserves

The California parties argue that Industrial reserves also should be omitted from the Standard rate because the reserves ensure the continuity of supply to firm power customers; that is, BPA will not interrupt the DSI's to serve nonfirm loads. Parmesano, LADWP, E-LA-01, 7; Buckingham, PG&E, E-GE-01, 6; Lindsay, SCE, E-CE-01, 4; Reply Brief, SCE, R-CE-01, 30-31; Reply Brief, CPUC, R-CP-01, 6.

Reserve costs are properly assignable to the Standard rate because they are a legitimate cost of generating FBS and new resource power. Metcalf, BPA, TR 5482-5484. Restriction rights on the DSI load allow BPA to build less reserve generation than it would otherwise need. If generation had been built instead, those costs would have been included in the Standard rate. These reserves support BPA's ability to generate Federal system power and, therefore, contribute to the availability of nonfirm energy. While it is true that BPA does not restrict the DSI's in order to make nonfirm sales, the existence of the reserves allows more nonfirm sales to be made without jeopardizing firm loads.

Exchange Costs

The PGP argues that the exchange increases the supply of nonfirm energy because it decreases the demand for firm power by increasing the rate. Garman, et al., PGP, E-PG-06R, 7.

PG&E refutes the assertion that exchange resources contribute to the supply of nonfirm energy. They assert that the total Pacific Northwest revenue requirement is not affected by who pays for the costs of exchange. Even if regional loads have declined, and assuming the PF rate is higher than in the absence of the Act, this load decrease is not necessarily due to the cost of the exchange. The IOU Residential Exchange customers experience a decrease in cost because of the exchange and, therefore, the net effect on loads due to the exchange may be an increase or decrease, depending on relative price response. Buckingham, PG&E, E-GA-02R, 6.

It is clear that exchange resources have very little effect on nonfirm energy availability. The amount of exchange resource equals the increase in PF load due to the Residential Exchange Program. Nonfirm energy is a result of Federal system resources. It is appropriate to use exchange resource costs when allocating costs to and designing firm rates because that is the allocation scheme required by the Regional Act. There is no such requirement for NF rates.

Diurnal Differentiation

The DSI's recommend that the Standard rate should be diurnally differentiated. Mizer, DSI, E-DS-13, 17; Mizer, DSI, TR 6955-6962. They assert that BPA has nighttime nonfirm loads that are low with respect to the amount of power available due to factors such as lower nighttime firm loads, minimum flow constraints, rebalancing ponds, and smoothing flows. However, the DSI's did not have a specific recommendation on how the Standard rate should be differentiated, nor did they know if it would result in a cost-based rate. Mizer, DSI, TR 6958, 6960. The Standard rate could appropriately be diurnally differentiated; however, a specific method has not been recommended, nor has there been any analysis of the revenue effect of such a change. A single Standard rate is simpler and easier to administer.

Decision

The Standard rate is determined in the same manner as the initial proposal with two exceptions. First, sales and revenues from all below-cost NF-83 and EB-83 rates are factored into the calculation to be consistent with the manner in which Spill revenues were treated in the initial proposal. Second, thermal resource capacity costs are removed from the Standard rate calculation. These capacity costs equal 1.8 mills/kWh (scaled) and will be assessed when guaranteed nonfirm energy is scheduled. The Standard rate reflects the cost of nonfirm energy from resource planning and operational perspectives. A nonfirm energy rate at BPA's average cost will result in a greater availability of nonfirm energy because it encourages the Pacific Northwest to build resources with high capital costs and low variable costs, and to market nonfirm energy more aggressively by using reservoir storage earlier in the operating year. The Standard rate reflects the operational reality of a large hydro system with substantial storage and baseload thermal resources; that is, it is impossible to determine the specific resource responsible for generating the energy.

d. Guaranteed Delivery

Issue #1

To what extent should BPA guarantee delivery of energy under the NF-83 rate schedule?

Summary of Positions

In BPA's initial proposal, BPA would guarantee to deliver, and the purchaser would commit to purchase, one-half of the daily amounts of energy offered for sale by BPA under the Standard rate. In this respect, the proposed NF-83 rate is the same as the NF-2 rate.

The CPUC argued that the guarantee to deliver should be extended to more than 1 day. Mattson, CPUC, E-CP-01, 20. PG&E stated that a 1-day guarantee was insufficient and that the guarantee should be at least 3, and preferably 5, days. Buckingham, PG&E, E-GA-01, 3. LADWP contended that BPA should offer guaranteed delivery for 5 consecutive weekdays. Noyes, LADWP, E-LA-01, 7-8. LADWP, PG&E, and CPUC allow for higher Standard rates if the guarantee is extended and provisions of offering the guarantee are amended. Parmesano, LADWP, E-LA-01, 9; Buckingham, PG&E, E-GA-01, 3; Mattson, CPUC, E-CP-01, 18-20. CEC suggests that a premium added to the NF-83 rate could adequately compensate BPA for the risks associated with guaranteeing nonfirm energy. Chamberlain, CEC, TR 5633-5635.

The PGP said that if BPA did not adopt their recommended form of nonfirm rate, BPA should abandon its Spill rate and offer a form of guarantee to its Standard rate when spill conditions exist. Garman, et al., PGP, E-PG-01, 64. The PPC favors a 3-day guarantee during spill conditions and a guarantee for periods up to three days when selling at the Standard rate. Opening Brief, PPC, B-PP-01, 24-25. The NWU's did not take any position on this issue, and in cross-examination stated that they were not prepared to comment on whether BPA should lengthen its guarantee under the proposed NF-83 Standard rate. Schultz, NWU, TR 6753-6754.

DSI's favor an extension of the guaranteed delivery provision for NF-83. They state that, when practicable, BPA should offer nonfirm energy on an assured basis for up to 3 days. Mizer, DSI, E-DS-13, 17.

Evaluation of Positions

BPA opposed extension of the guaranteed delivery provisions beyond the 50 percent of the nonfirm energy offered by BPA through the next workday. Extension of the guaranteed provisions beyond the day or days for which BPA normally preschedules power deliveries would pose difficulties for BPA schedulers. BPA believes that an obligation to guarantee delivery of more than half of the energy it offers to sell when its system is not spilling might reduce the amounts of nonfirm it offers to sell. Dean, BPA, E-BPA-33, 2. Extension beyond one day would require BPA to make commitments to deliver nonfirm energy before BPA knows the amounts of firm energy which its generating utility customers will request. Dean, BPA, E-BPA-33, 3. Guaranteeing deliveries for longer than 1 day would take away from BPA the flexibility it now has to offer nonfirm energy for sale as the last increment of energy available from the system, thus matching load to all of BPA's generating capability and maximizing BPA's total sales. Dean, BPA, TR 5625-5626.

On the other hand, California parties' witnesses argued in favor of a longer guarantee, primarily on the basis that nonfirm energy having a longer guarantee would be of more value to the California purchaser, but also on the basis that BPA would obtain more revenue as a result of a longer guarantee. Noyes, LADWP, E-LA-01, 7-8. LADWP testified that they would often purchase nonfirm energy from BPA and reject offers from others priced as much as 5 mills/kWh less than the BPA offer, depending on market conditions, if BPA's nonfirm energy were guaranteed for five consecutive weekdays. Noyes, LADWP, E-LA-01, 7-8.

LADWP and PG&E tie the price of nonfirm energy to the guarantee provision. LADWP states that a 5-day guarantee offered in a nondiscriminatory manner would provide justification for inclusion of capacity costs because "it may require changes in the operation of BPA's hydro system, and additional costs may be incurred." LADWP allows that the rate could justifiably be set equal to the average PF rate assuming 100 percent load factor. Without such a guarantee, the rate may only be as high as the average PF energy charge. Parmesano, LADWP, E-LA-01, 8-9. PG&E asserts that a 3- to 5-day guarantee would justify inclusion of capacity costs in the Standard rate. The appropriate charge for this service would be 3.0 mills/kWh which is based on the capacity-related costs of FBS, NR, other, deferral, cash lag, and conservation. Buckingham, PG&E, E-GA-01, 3, 7. The CPUC does not allow for a rate differential due to a guarantee, but proposes that the premium on which their alternative Standard rate is based would be higher with a nondiscriminatory, longer guarantee in recognition of added costs BPA would incur. CPUC recommends a single Standard rate for ease of administration, understanding, and revenue forecasting. Mattson, CPUC, E-CP-01, 19-20.

DSI's favor increasing guarantees of delivery of nonfirm energy since it would cost-justify inclusion of fully allocated costs in the Standard rate. Mizer, DSI, E-DS-13, 17; Saxton, DSI, TR 5616-5629; Opening Brief, DSI, B-DS-01, 80.

The CEC recommends that BPA create a new "premium nonfirm energy" rate which would be offered on a 3-day guaranteed basis and would carry a 1 or 2 mill/kWh premium over the Standard rate. Opening Brief, CEC, B-CC-01, 54-57.

BPA concurs with CPUC that a single Standard rate facilitates administration, understanding and revenue forecasting. In addition, BPA was not able to identify a cost basis for differentiating the rate based on the 1-day guarantee contained in the current NF-2 Standard rate. Metcalf, BPA, TR 7270. However, BPA has attempted to reflect cost to the maximum extent practical in the NF-83 rate. A differential may offer an incentive to make guaranteed nonfirm energy available, and to compensate BPA for the increased risk of guaranteeing nonfirm energy delivery. Thermal resource capacity costs represent a reasonable estimate of the additional costs of a multi-day guarantee.

Northwest utilities either favor or do not seem to be concerned about the possibility of increasing either the amount of nonfirm energy or the length of time nonfirm energy is offered on a guaranteed basis. They offered no testimony opposing such a change, nor did they cross-examine the proponents of increasing guarantees to any significant extent. The PPC favor a guarantee of up to 3 days when BPA is offering Standard rate energy for sale. During spill periods, they propose a guarantee for 3 days. The guaranteed energy should be subject to interruption to protect contractually firm loads or in the event of a resource outage. Opening Brief, PPC, B-PP-01, 24-25. The PGP supports a guarantee at the Standard rate during periods of spill based on an alternative nonfirm rate in which the Spill rate is eliminated. Garman, et al., PGP, E-PG-01, 64. The DSI's favored an extended guarantee of up to three days when practicable. Mizer, DSI, E-DS-13, 17; Reply Brief, DSI, R-DS-01, 63.

The PPC objects to the draft decision in the Evaluation of the Record, p. 237, in which thermal capacity costs would be removed from the calculation of the Standard rate and used as the surcharge for guaranteed delivery. They argue that the guarantee is an additional benefit and should command an additional premium over the costs associated with the Standard rate. Because the Spill rate is priced below cost, it is inappropriate to further discount this rate. The guarantee will confer benefits on the Southwest in addition to the large monetary benefit received. Therefore, the added benefit should raise the price on guaranteed energy, not lower the price on nonguaranteed sales. Reply Brief, PPC, R-PP-01, 16-17.

The PPC does not state how it would determine the guarantee adder nor what the justification would be for charging guaranteed nonfirm energy purchasers more than the average cost, including all capacity and energy costs, of generating and transmitting FBS and new resources. The added benefits which the guarantee will provide correspond to thermal capacity costs. It is true, as the PPC states, that "The existence of thermal resources in the Pacific

Northwest is critical to the offering of nonfirm power to the Southwest market." Reply Brief, PPC, R-PP-01, 16. Under BPA's proposal, nonguaranteed nonfirm energy purchasers will share in paying 87 percent of those thermal resource costs.

The PPC appears to have interpreted BPA's draft decision to lower the Spill rate by 2 mills/kWh to 11 mills/kWh to be based on the removal of the guaranteed delivery surcharge from the initial proposal Spill rate. Reply Brief, PPC, R-PP-01, 16-17. However, the lower Spill rate is based on factors concerning the changes in availability of the NF-83 rate rather than the guaranteed delivery surcharge. BPA will sell more nonfirm energy at the final NF-83 Standard rate compared to the NF-83 initial proposal, so revenue considerations are not as large a factor in determining the level of the Spill rate for the final proposal. By setting the Spill rate at the lower end of Northwest baseload thermal variable costs, BPA insures that those plants will not be run in competition with BPA.

Decision

It appears that BPA can satisfy most, if not all, the concerns stated by the various witnesses by extending the guarantee, particularly since BPA's Northwest customers do not appear to be concerned about increasing the guarantee provisions under the NF-83 rate.

On the first and last working day of each week, or more often if BPA determines that it is appropriate, BPA will indicate the amounts of nonfirm energy available for delivery on a guaranteed basis. On the first working day of each week BPA will indicate the daily (and, if necessary, the hourly) amounts that it is willing to guarantee through at least the coming Friday. On the last working day of each week BPA will so indicate through at least the coming Tuesday. Such daily (or hourly) amounts may be as small as zero or as much as all the nonfirm energy BPA plans to offer for sale on such days. BPA may so offer to guarantee delivery of nonfirm energy offered for sale at the Standard rate, Spill rate, Displacement rate, or Contract rate.

When BPA makes Standard and Spill rate nonfirm energy available on a guaranteed basis, it will offer that energy in sequence to the various priority classes of purchasers. To the extent that BPA offers and the purchaser requests delivery of nonfirm energy on a guaranteed basis, that energy will have a surcharge applied to it and the purchaser will not be able to unilaterally reduce its request (it will be take-or-pay). BPA will subsequently offer any guaranteed energy which has not been requested and which BPA determines it will make available on a nonguaranteed basis, together with such additional amounts of energy as BPA determines are available on a nonguaranteed delivery basis. BPA will offer such energy in sequence to the various priority classes of customers for delivery on a nonguaranteed delivery basis on the following one or more days for which preschedules are normally prepared.

The charge for guaranteed delivery of nonfirm energy is 1.8 mills/kWh with the exception of guaranteeing Displacement rate energy for nuclear plants. This differential for guaranteed nonfirm energy equals the average thermal resources capacity cost and will compensate BPA for the additional risk undertaken by guaranteeing service.

As in the NF-2 rate, BPA may reduce amounts of nonfirm energy which are scheduled for delivery on a guaranteed basis only if it must reduce such deliveries in order to serve firm loads because of an unexpected generation loss in the Pacific Northwest or if BPA and the purchaser agree to reduce the scheduled amounts.

This procedure for guaranteeing delivery of nonfirm energy will give BPA the flexibility of not guaranteeing deliveries when BPA may not have the ability to make the deliveries, and yet will result in BPA offering to guarantee delivery of more than half of the nonfirm energy it offers to sell during the vast majority of each year. The surcharge will not only give BPA an incentive to offer to guarantee the maximum amounts of energy which it reasonably can, but it will also have the effect of not having limited offers of guaranteed energy taken by those purchasers with higher priority access to BPA nonfirm energy unless that energy has some additional value to those purchasers. Extending the guaranteed delivery provisions to Spill rate energy should be very beneficial to the California utilities because much of BPA's nonfirm energy which will be purchased by those utilities may be sold at the Spill rate. Extending the guaranteed delivery provisions to Displacement rate energy should be beneficial to the operators of thermal plants which are shut down with purchases of such energy because it will give them more notice of their need to return those plants to service than they would have if the energy were delivered on a nonguaranteed basis.

Issue #3

Is the NF-83 Standard rate consistent with Federal Energy Regulatory Commission orders?

Summary of Positions

SCE argues that the Federal Energy Regulatory Commission (Commission), in its Order Confirming and Approving System Rates on a Final Basis (approving BPA's 1979 rates), held that cost-of-service based rates are required by the statutes governing BPA's rates. 23 FERC 61,342 (1983). Opening Brief, SCE, B-CE-01, 17. The CEC argues that this FERC order does not allow BPA to price nonfirm energy higher than the level of the energy charge in BPA's PF rate. Opening Brief, CEC, B-CC-01, 33-34.

PP&L argues that the NF-83 Standard rate is lower than the maximum rate that the FERC indicated was allowable. Opening Brief, PP&L, B-PL-01, 41. The DSI's argue that the inclusion in the Standard rate of the costs of future thermal resources is consistent with the FERC order approving BPA's 1979 rates. Opening Brief, DSI, B-DS-01, 94.

Evaluation of Positions

Contrary to the assertion of SCE, there is no basis for reaching the conclusion that the Commission held in its order approving BPA's 1979 rates that the statutes governing BPA's rates mandate a cost-based nonfirm energy rate. Rather, the Commission questioned whether BPA had fully supported its choice of the value-based H-6 Nonfirm Energy rate. In addition, the Commission suggested that BPA develop a fixed, cost-based nonfirm rate. As discussed elsewhere, BPA's NF-83 rate is in harmony with that suggestion, as the Standard rate is both fixed and cost-based. BPA departs from that fixed, cost basis only in the face of competitive market conditions.

BPA also disagrees with the CEC's interpretation of this FERC order, that BPA may not price nonfirm energy higher than the level of the energy charge in BPA's firm power rates. Contrary to CEC's contention, the Commission does not base its pricing suggestion on a comparison of nonfirm energy to the energy component of firm power schedules. The section of the order relied on by CEC compares the price of "nonfirm energy" with the price of "firm power," and suggests that the former, being of lower quality, should be priced lower than the latter. 23 FERC at 61,739. BPA's rate proposal is in harmony with this suggestion, as its NF-83 rate is lower than all of its firm power rates.

Consistent with the suggestion of the Commission, the Standard rate is not based only on hydro system costs. Rather, in recognition of critical water planning (discussed below), it is based on the costs of operating the system as a whole. In noting that BPA apparently assumed in the 1979 case that the only allowable costs upon which the nonfirm energy rate can be based are variable hydro costs and some Intertie costs, the Commission stated: "[t]o the contrary, Bonneville's underlying assumption that only system hydro costs are incurred to serve nonfirm customers appears to have no reasonable basis. Bonneville's operational realities are such that it purchases energy at a higher cost than its own generation costs in order to serve its customers' needs, including the needs of its nonfirm customers." 23 FERC at 61,740.

SCE, LADWP, and PG&E argue that it is inappropriate for BPA's NF-83 Standard rate to include the costs of capacity, Supply System, reserves, conservation, deferral, cash lag, and Capacity/Energy Exchange. Opening Brief, SCE, B-CE-01, 32; Opening Brief, LA/PG&E, B-LA/GA-01, 18. Generally, they object to these types of system costs on the grounds that they do not contribute to the availability of nonfirm energy. The Commission, however, has taken a different view of such costs, in acknowledging the "operational realities" of the BPA system. 23 FERC at 61,740. The Commission has recognized that these types of costs are the result of the operation of the BPA system as a whole. Indeed, several of the costs the California parties have objected to, such as Supply System costs, fixed costs of energy resources, conservation costs, and capacity costs, are specifically cited by the Commission as costs appropriately included in BPA's nonfirm energy rate:

> Additionally, in calculating the cost of the nonfirm energy, it would be reasonable to include the allocated costs of any future power resources which are currently being incurred and are intended to benefit Bonneville's nonfirm customers. These costs would include all allocated energy costs (be they fixed or variable), and portions of conservation costs, hydro capacity used almost solely for nonfirm power production, etc. 23 FERC at 61,740.

BPA believes that the NF-83 Standard rate is consistent with the Commission's suggestion that BPA develop a fixed cost-based rate. 23 FERC at 61,740. The Standard rate is fixed at the average cost of service by FBS and new resource power, plus the average cost of related transmission. BPA departs from this fixed, cost basis only in the face of competitive market conditions which dictate that BPA can recover something less than its costs of producing nonfirm energy. This is not only consistent with sound business principles, it is consistent with a recent FERC order and the statutory standards under which FERC reviews BPA's rates.

In its Order Confirming and Approving Rates on a Final Basis (approving BPA's 1981 and 1982 rates), the Commission expressed concern over revenue underrecoveries resulting from the difference between actual loads and forecast loads. 23 FERC 61,378, 1983. The Commission stated: "We suggest that the Administrator carefully consider future load forecasts in light of market conditions existing at the time of BPA's rate filings." 23 FERC at 61,800. In designing its NF-83 rate BPA has done what the Commission suggested. It has examined the projected load at the cost-based Standard rate under forecast market conditions and has prudently designed two rates below cost (Spill and Displacement) in order to assure BPA's ability to compete in the nonfirm market. To adhere to its fixed, cost-based rate in the face of adverse market conditions would jeopardize BPA's ability to repay its Federal obligation. This would be contrary to section 7(a)(2) of the Regional Act, which requires the Commission to find that BPA's rates yield revenues sufficient to repay the Federal investment over a reasonable number of years. 16 U.S.C. §839e(a)(2)(A).

The NF-83 rate is also consistent with the Commission's order approving BPA's 1979 rates in that it provides an "equitable sharging of the benefits of non-firm sales between the northwest and southwest customers." 23 FERC at 61,744. Such an equitable sharing is consistent with section 5 of the Northwest Preference Act: "All benefits from such exchanges, including resulting increases in firm power shall be shared equitably by the area involved, having regard to secondary energy and other contribution made by each." 16 U.S.C. §837d. Unreasonably low below-cost nonfirm energy rates, such as those advocated by the California parties, would result in an inequitable sharing of the benefits. The Southwest would enjoy the benefits of the nonfirm energy produced by the FCRPS, while realizing little of the burden of the cost of building the Federal system and operating it on critical water.

Decision

BPA's NF-83 Standard rate is consistent with Federal Energy Regulatory Commission orders.

e. Elimination of the Spill Rate

Issue #1

Should the Spill rate be eliminated?

Summary of Positions

In its initial proposal, BPA suggested that the elimination of the NF-83 Spill rate was an alternative seriously being considered for the final proposal. Analyses indicated that if this alternative was adopted, expected revenues from NF-83 sales would increase, and surplus firm power would become more marketable because of the increase in the price of nonfirm energy. Metcalf, BPA, E-BPA-32, 56. BPA demonstrated that while potential competition could reduce the expected benefits of eliminating the NF-83 Spill rate, there was no information available that would indicate that there were substantial quantities of power available to California at rates less than the NF-83 Standard rate but greater than the NF-83 Spill rate. Wedlund, BPA, E-BPA-48R, 2-4.

California parties unanimously oppose elimination of the NF-83 Spill rate. LADWP and PG&E argue that potential competition would reduce the estimated benefits of eliminating the Spill rate. This competition would come from utilities with low cost thermal resources inside the Region and from outside of the Pacific Northwest. Parmesano, LADWP, E-LA-01, 12; Buckingham, PG&E, E-GE-01, 9; McKenzie, PG&E, TR 9135-36; Chamberlain, CEC, TR 9170. Another concern expressed by California parties was that elimination of the Spill rate might jeopardize future Intertie expansion. Buckingham, PG&E, E-GE-01, 8; McKenzie, PG&E, TR 9138; Cooley, SCE, TR 9159; Chamberlain, CEC, TR 9173. Another argument against elimination of the NF-83 Spill rate was that it would increase the proportion of total revenues received from nonfirm purchasers, since the excess revenues would be used to reduce BPA's firm power rates. Parmesano, LADWP, E-LA-04R, 9.

The California parties also contend that the computer program used to evaluate the impact of eliminating the Spill rate contains faulty assumptions. McKenzie, PG&E, TR 9135-36. The California parties also maintain that elimination of the Spill rate will reduce the amount of power available for thermal displacement outside the region, increase BPA's revenue stability problems, and lead to lengthy court battles. Fairchild, CPUC, TR 9164-65; Chamberlain, CEC, TR 9175.

The California parties have also criticized BPA's tentative decision to rely less extensively on the Nonfirm Spill rate, and repeat their claim that: ". . . elimination (or emasculation) of the Spill rate offers Northwest IOU's and others, who compete with Bonneville to sell nonfirm energy, greatly increased opportunities to undercut BPA's price." Reply Brief, LADWP, R-LA-01, 2. It was also claimed that there were <u>no</u> (revenue) projections in the record that take into account the changes in the rates finally proposed. Reply Brief, SCE, R-CE-01, 2.

Northwest parties support elimination of the Spill rate. The DSI's support eliminating the Spill rate because they feel it would improve the marketability of BPA's surplus firm power. Mizer, DSI, E-DS-13, 6. APAC indicated that elimination of the Spill rate would be in the best interests of BPA's regional customers. Cook, APAC, E-PA-08R, 19. The WWPUD's support the use of the NF-83 Standard rate in conjunction with the Displacement rate to insure the efficient displacement of thermal resources. Hutchison, et al., WWPUD, E-WW-01, 45. The generating public utilities support elimination of the Spill rate if BPA fails to adopt a share-the-savings rate for nonfirm sales. Garman, et al., PGP, E-PG-01, 64. Finally, the investor-owned utilities support elimination of the NF-83 Spill rate if it would lead to increased BPA revenues. Schultz, NWU, E-NW-07, 7.

In addition to the above comments, the NWU's offered a specific proposal concerning Displacement rate operation under the NF-83 proposal eliminating the Spill rate. The proposal recommended shifting to the Displacement rate when (1) BPA determines that its net revenue would increase, and (2) the FCRPS is spilling or would spill absent such a shift. Schultz, NWU, E-NW-7, 7. APAC agrees with NWU's that BPA should remain at the Standard rate until net revenues can be increased by shifting to the Displacement rate. Cook, APAC, E-PA-08R, 19.

Evaluation of Positions

Effect on BPA Revenues

California parties argue that the nonfirm energy market has not been modeled correctly for the determination of nonfirm energy revenues. "The worst of these is the assumption that competition from other Pacific Northwest sellers of nonfirm energy will cost BPA very few sales, even though the potential 20 mill standard rate that's been proposed would appear to give those sellers plenty of room to undercut BPA's nonfirm price." The California parties claim that there is approximately 6,000 megawatts of generation capacity in the Pacific Northwest with variable cost less than 20 mills/kWh which would provide substantial competition for sales to California, and that the program failed to adequately reflect minimum load conditions which cause the Intertie to be unloaded even at the current 9 mills/kWh Spill rate. McKenzie, PG&E, TR 9135-9136. They also assert that competition from Pacific Northwest utilities for the California market will lower BPA's sales and revenues.

It should be noted that Pacific Northwest thermal generation is usually needed to serve Pacific Northwest firm loads. BPA's Nonfirm Revenue Analysis Program (NFRAP), which forecasts nonfirm energy revenues based on an analysis of 40 water years, modeled Pacific Northwest competition under alternative assumptions. The first assumption is "proportional spill" which models the effect of BPA and Pacific Northwest utilities spilling in proportion with each utilities' total amount of nonfirm energy compared to the total amount of nonfirm energy in the Pacific Northwest. Under that assumption, NFRAP demonstrated that BPA would collect approximately \$63 million more if the Spill rate were eliminated than it would collect if the proposal of a 13.0 mills/kWh Spill rate were adopted. The second assumption under which NFRAP was run was that all available non-Federal power is marketed before BPA enters the market. That is, all Pacific Northwest utilities sell all their available nonfirm energy on the Intertie before BPA is allowed to sell its nonfirm energy. This assumption is called "BPA absorbs all the spill" and is the most conservative assumption possible concerning competition from other Pacific Northwest utilities. Even under this very conservative assumption, BPA still received approximately \$33 million more revenue eliminating the Spill Rate than with a 13.0 mills/kWh Spill rate. Wedlund, BPA, E-BPA-48R, Attachment 4, 1.

California parties point out other aspects of the nonfirm energy market that may not be modeled adequately. Parmesano, LADWP/PG&E, E-LA/GA-01, 10-11. Factors that would affect nonfirm energy revenues are Northern California hydro generation, minimum generation constraints, Intertie loopflow, and California nuclear plants forecast to come on-line during the rate period. BPA maintains that it has modeled the nonfirm energy market using the best information available at this time. Adjustments are made to reduce the California market to account for loop flow, maintenance, firm contracts and export of non-Federal firm surplus. BPA, E-BPA-4, Appendix C. The NFRAP also assumes that B. C. Hydro has 1500 megawatts available for sale in September and October and 1000 megawatts in November, December, and January. The factors cited by the California parties are primarily structural determinants of the nonfirm energy market. That is, BPA could experience a reduction in sales because of these factors regardless of the NF-83 rate level or design.

California parties also assert that competition from outside the region, either B.C. Hydro, or alternate suppliers whose power would not flow over the Intertie, would reduce nonfirm revenues. Parmesano, LADWP, E-LA-01, 12. Buckingham, PG&E, E-GA-01, 9. As stated above, sales by B. C. Hydro have been accounted for in the NFRAP. BPA performed a sensitivity analysis of the effects of different levels of competition on nonfirm energy revenues. The Intertie capacity was reduced by increments of 200 megawatts assuming a scenario of proportional spill and one in which BPA absorbs all the spill. The Intertie reduction represents increasing levels of competition which would, for example, account for sales to California by B. C. Hydro which are in addition to sales assumed in the base case, or from any source outside the Pacific Northwest region including northern California hydro generation. Wedlund, BPA, E-BPA-48R, Attachment 4. Under the proportional spill scenario, competition could displace more than 1000 megawatts of BPA nonfirm sales on the Intertie before BPA revenues would be lowered by eliminating the Spill rate. In the most conservative scenario in which BPA absorbs all the regional spill, competition could displace over 400 megawatts before BPA would lose revenues by eliminating the Spill rate. Furthermore, little evidence has been presented that substantial amounts of power are available to the Pacific Southwest from other regions at rates less than BPA's proposed rates. Wedlund, BPA, TR 7957. PP&L contends that California parties' claims that BPA will face increased competition from outside the Northwest region if it sells at the Standard rate year-round are groundless. The only purchase made at less than BPA rates in the last year identified by SCE was slightly more than 1 average megawatt. Opening Brief, PP&L, B-PL-01, 43-44.

The DSI's and BPA have stated that inclusion of a Nonfirm Energy Spill rate may jeopardize projected sales of surplus firm power and lead to a revenue recovery problem. Mizer, DSI, E-DS-13, 14; Metcalf, BPA, E-BPA-32, 56. During FY 1983, BPA has had considerable difficulty marketing power under the SP-1 and SE-1 rates because of the relatively low rates for, and relative abundance of, nonfirm energy. Metcalf, BPA, E-BPA-32, 56. Most of the nonfirm energy sold to California is sold at the Spill rate. The greater the cost differential between the surplus power rates and the NF Spill rate, the lower the probability of selling any power at the SP rate. Metcalf, BPA, TR 5457. It should be noted that surplus firm contracts with California allowed the displacement of firm power with nonfirm energy. BPA's ability to meet its repayment obligations will be impaired if projected surplus firm power sales do not materialize. BPA's nonfirm energy revenue forecast accounts for substantial competition. BPA pointed out that substantial additional competition from inside or outside the Northwest would be necessary before a reduction in Federal nonfirm energy revenues would be expected to occur. Wedlund, BPA, E-BPA-48R, Attachment 4, 2.

The evidence with respect to the effect of elimination of the Spill rate on BPA's revenues is mixed. The evidence suggests that elimination would likely increase revenues in most circumstances. Nevertheless, there are inevitably many uncertainties associated with this large a change. Metcalf, E-BPA-32, 56. There may well be times when implementation of the Spill rate would increase BPA's revenues even if the opposite is true most of the time.

Thermal Displacement

PG&E argues that eliminating the Spill rate may result in situations in which a Pacific Northwest utility would find it economically advantageous to operate its thermal resource and sell the output to California rather than buy nonfirm energy at the Displacement rate. Buckingham, PG&E, E-GA-01, 9. The NWU's and DSI's agree this could occur. Schultz, NWU, TR 6751; Mizer, DSI, TR 6974-80. It is unclear whether this situation would occur, and, if it did, how often this would happen. Uncertainty exists because a utility could alternatively purchase Displacement rate energy to displace a thermal resource and continue selling nonfirm in the Intertie based on costs of another resource. Dean, BPA, TR 5766.

Intertie Expansion

California parties also claim that future Intertie expansion may be jeopardized if the Spill rate is eliminated. Buckingham, PG&E, E-GA-01, 8. The converse of this statement must also be considered -- BPA must receive a sufficient level of revenue from sales over the Intertie in order to justify another interconnection. Just as the nonfirm market is a crucial determinant of the high capital cost/low production cost resource mix in the Pacific Northwest that serves to increase the availability of nonfirm energy, Schultz, NWU, E-NW-25R, 4, it is also a crucial determinant in the decision to build another Intertie. Evidence suggests that benefits of nonfirm energy are greater to the Pacific Southwest even at the Standard rate than to the Pacific Northwest. The NWU's contend that BPA's proposed Standard rate is substantially lower than half the current cost of generating electricity by burning oil or gas, even assuming BPA's incremental cost to be zero. Schultz, NWU, E-NW-25R, 5.

PG&E acknowledged that other factors as well as the Spill rate would be considered in intertie expansion planning. Buckingham, PG&E, TR 7176. P&GE noted that BPA's own studies indicate that at current Nonfirm Energy rates Intertie expansion would increase BPA revenues by $126 million, while elimination of the Spill rate would increase revenues by only about $60 million. A review of the analysis cited by PG&E (which is not part of the hearing record) indicates that the $126 million figure represents the net present value of life cycle benefits from Intertie expansion to BPA, not the single year increase in revenues. Clearly, this is an inappropriate comparison since the $126 million amount includes benefits beyond the test period.

LADWP claims that ". . . it is extremely doubtful that California utilities could have justified the expense of design, construction, and maintenance of the DC Intertie if it were to be used primarily for obtaining a product as unsecure as nonfirm energy." Noyes, LADWP, E-LA-05R, 11. This statement implies that at least one California utility does not weight the nonfirm energy market very heavily in determining their intertie expansion plans.

PP&L asserts that BPA should not take seriously threats that a second Intertie would be opposed by California parties if the Nonfirm Energy rate remains at a cost-based level the year around. They think it unlikely that California utilities will ". . . throw away billions of dollars of future benefits if offered by another intertie, simply to posture over loss of the Spill rate." Opening Brief, PP&L, B-PL-01, 45-46.

Criteria for Implementing the Spill Rate

NWU's recommend, if the Spill rate is eliminated, that BPA should shift to the Displacement rate only when the FCRPS is spilling or about to spill and net revenues would increase by such a shift. Schultz, NWU, E-NW-7, 7. APAC concurs with the latter condition. Cook, APAC, E-PA-08R, 19. BPA develops the Standard rate to be equal to the cost of nonfirm energy. When BPA sells nonfirm energy below the Standard rate, BPA is not able to collect the full cost of the energy. Thus, it appears reasonable to shift from the Standard rate to the Displacement rate only when it has been determined that net revenues will increase. Due to the nature of the market, it would seem that such a situation would occur only when the FCRPS is spilling or would imminently spill.

BPA's draft decision in the Evaluation of the Record, p. 242, recommended that the Spill rate be implemented when it was determined that BPA's net revenue would increase and the FCRPS was spilling or forecast to spill. CEC argues that BPA has overlooked the fact that excess PNW thermal can and should compete with BPA spill sales if the Standard rate is charged. They argue that BPA cannot force PSW utilities to buy spill energy at an artificial price. The NF-83 rate is highly unstable and will likely injure BPA and California utilities. Reply Brief, CEC, R-CC-01, 12. PG&E is concerned that BPA's decision to implement the Spill rate only when forced to do so is likely to create opportunities for competing nonfirm sellers to undercut BPA's price. Reply Brief, PG&E, R-GA-01, 2, 4-6.

There appears to be no reason that excess PNW thermal would not compete with BPA nonfirm energy during periods of spill. BPA has accounted for such competition in its rate schedule. If revenues from sales at the Standard and Displacement rate are less (mostly due to competition) than revenues BPA could receive by implementing the Spill rate, BPA will drop the Nonfirm Energy rate to the Spill rate. Regardless of the condition of the FCRPS, the Standard rate is the cost of nonfirm energy. If PSW utilities find it economically prudent to purchase such energy to displace high cost resources, they would likely buy the Standard rate energy. If it is not in their economic interest because they are not able to displace more resources or can do so with alternative purchases, BPA will not fill the intertie with nonfirm energy. BPA can offer energy at the Displacement rate to such utilities, or depending on the market, implement the Spill rate. In either case, BPA will be offering below-cost nonfirm energy for sale.

Concerning BPA's draft decision, PPC feels that BPA should establish a formal policy to establish when the Spill rate will be offered. Without it, they argue that PSW parties will still play a waiting game in the hope that

BPA can be coerced into dropping from the Standard rate to the Spill rate. It is unclear to the PPC why reducing the Nonfirm Energy rate to the Spill rate would further encourage thermal displacement. Reply Brief, PPC, R-PP-01, 18-19.

LADWP charges that BPA's proposal in the draft decision gives BPA unlimited discretion to price nonfirm energy and the rate is really a "revenue enhancement rate." BPA is no longer constrained by an objective situation to trigger a change in rates. Reply Brief, LADWP, R-LA-01, 15.

BPA has stated its criteria for implementing the Spill rate. These criteria constitute an adequate guideline for BPA schedulers. BPA will try to sell all nonfirm energy at the cost-based Standard rate. It will implement the Spill rate when increased levels of thermal displacement and revenues will result. This situation will occur when the PSW is able to make alternative purchases below the Standard rate and if low-cost PNW thermal is operating when BPA is not displacing it with Displacement rate energy.

SCE regards the rate as a revenue maximization rate and charges that BPA has disregarded "consequences to the national policy of efficient use of renewable resources and the mitigation of the adverse environmental impacts in the use of fossil fuels." Reply Brief, SCE, R-CE-01, 25-26. PG&E contends that environmental damage due to spill will increase. Reply Brief, PG&E, R-GA-01, 4-5.

However, it is clear that BPA has considered the environmental impacts of the NF-83 rate. BPA has two primary goals: thermal displacement and collecting an adequate level of revenues. The Displacement rate is specifically designed to displace thermal resources which also has the effect of lessening spill. In addition, the Spill rate will be implemented to increase thermal displacement as well as revenues.

Congressman Weaver argues that the Northwest could use Displacement rate energy to capture use of the Intertie and exclude BPA from all or a part of the California market. Reply Brief, Weaver, R-WE-01, 1-7. However, Congressman Weaver overstates the amount of displaceable PNW thermal. The numbers quoted in his brief are unsubstantiated. BPA feels that such thermal is appropriately accounted for in the Nonfirm Revenue Analysis Program that models the nonfirm energy market. BPA is accounting for extra- and intraregional competition in the NF-83 rate by including the Spill rate.

Decision

BPA will continue to have a Spill rate in the NF-83 rate. However, movement to the Spill rate will no longer be required during spill or forecasted spill conditions. The evidence in the record indicates that elimination of the Spill rate would probably increase the revenues BPA would collect from the NF-83 rate in the initial proposal. However, there appears to be some uncertainty concerning the adequacy of the Nonfirm Revenue Analysis Program in modeling the nonfirm energy market without a BPA Spill rate. BPA is particularly concerned that there may be significant levels of Pacific Northwest thermal generation that would not be displaced, and that competition may not have been accounted for completely in the revenue analysis.

Uncertainty also exists concerning intertie expansion plans as it relates to the goal of rate continuity.

Discussions of the Spill rate elimination proposal have advanced concepts that have been applied to the NF-83 final proposal. Parties proposed that with the Spill rate eliminated BPA not shift to the Displacement rate until it was determined that BPA's net revenue would increase and the FCRPS was spilling or forecast to spill. With the Spill rate retained, these criteria are also applicable to the decision to move from the Standard rate to the Spill rate. In most circumstances BPA's revenues during spill conditions would be greater from a combination Standard rate and Displacement rate than from Spill rate and Displacement rate. It also appears that the Standard rate and Displacement rate combination will, in most circumstances, result in economic displacement of thermal plants. Since BPA is collecting less than the full cost of nonfirm energy when marketing at the Spill rate, it makes sense to delay implementation of the Spill rate for as long as is prudent.

As a spill condition approaches, rather than losing revenues by immediately implementing the below-cost Spill rate, BPA will use the Displacement rate to displace resources with decremental costs too low to displace with the Standard rate, much as was discussed in the elimination of Spill rate scenarios. Only when it appears that moving to the Spill rate will result in greater BPA revenues or more thermal displacement is such a move prudent. This approach has much of the revenue advantages of the elimination of the Spill rate alternative without the inherent risks.

Issue #2

Does the degree of flexibility present in the Nonfirm Energy rate violate BPA's Procedures or the ratemaking principles contained in the statutes enumerated in section 7(k) of the Regional Act?

Summary of Positions

The CEC argues that the discretion granted to BPA schedulers in the Nonfirm Energy rate violates the ratemaking principles contained in the three statutes enumerated in section 7(k) of the Regional Act. Reply Brief, CEC, R-CC-01, 12. PG&E argues that the degree of discretion contained in the implementation of the Spill rate is inconsistent with the definition of a rate contained in BPA's regulations. Reply Brief, PG&E, R-GA-01, 9.

Evaluation of Positions

The CEC contends that BPA schedulers have "unbridled discretion" as to whether to offer the spill rate or not. Such discretion, argues CEC, violates the rate directives contained in the Bonneville Project Act, the Federal Columbia River Transmission System Act, and the Flood Control Act of 1944. It is difficult to evaluate the merits of the CEC's argument. This is because the CEC is not specific with respect to the nature of the alleged statutory violations, with the exception of its contention that the "fair and reasonable" directive of the Flood Control Act has been violated. Reply Brief, CEC, R-CC-01, 13.

The issue is not whether BPA schedulers are fair and reasonable, but whether the terms and conditions of the Nonfirm rate schedule are fair and reasonable. The discretion referred to by the California parties lies with the Administrator. The schedulers implement the terms set forth in the Nonfirm Energy rate schedule. It is true that the Administrator has some discretion under the Nonfirm Energy rate schedule. This discretion is not unduly broad, however, nor is it unfair or unreasonable. BPA needs flexibility given the nature of nonfirm energy, whose availability varies. It is also appropriate given the highly competive nonfirm market in which BPA operates. Finally, discretion is necessary to achieve the goals of displacing thermal resources and increasing revenues.

PG&E's contends that the amount of discretion allowed BPA's schedulers under the Nonfirm Energy rate is so broad that BPA is "silent on such a fundemental issue as when a specific rate schedule will be in effect." PG&E argues that this is a violation of BPA's procedures. Reply Brief, PG&E, R-GA-01, 9. The definition relied upon by PG&E provides: "Rate. The monetary charge or the formula for computing such a charge for any electric service provided by BPA, including charges for capacity (or demand), energy, or transmission service , and discounts or surcharges; . . ." Procedures Governing Bonneville Power Administration Rate Adjustments, §1010.2(g), 47 Fed. Reg. 6243 (1982).

It is unnecessary to reach the issue of what BPA's regulations require, because the Nonfirm Energy rate schedule is not silent on the question of when the rate is in effect. The question of when the rate is in effect is addressed throughout the schedule. Several examples serve to illustrate this. The availability section of the schedule indicates that nonfirm energy may be delivered under emergency conditions. The market rates section of the schedule indicates that more than one rate may apply at any given time, but that offers of nonfirm energy may not be made at the Standard rate and Spill rate at the same time. The Displacement rate section of the schedule specifies that Displacement rate energy may be made available when all markets have been satisfied at the Standard or Spill rate. The Displacement rate section also indicates that a condition of purchasing Displacement rate energy is that purchasers must shut down or reduce the output of the displaceable resource. These examples are not intended to provide an exhaustive list of all of those portions of the Nonfirm Energy rate schedule which indicate when a particular rate is in effect. However, they serve to illustrate that BPA is not "silent" on the question, contrary to the contention of PG&E.

Decision

The flexibility present in the Nonfirm Energy rate does not violate BPA's procedures or the Regional Act.

f. Level of Spill Rate

Issue #1

Is the level of the Spill rate appropriate?

Summary of Positions

In the initial proposal, BPA set the Spill rate at 13.0 mills/kWh using the weighted average variable cost of Pacific Northwest coal plants as a guideline. The variable O&M and fuel costs for most of the plants was found in the Pacific Northwest Utilities Conference Committee (PNUCC) Thermal Resources Database, December 1982, and escalated to the middle of the test year. Displacing some thermal resources and enhancing revenue recovery were major goals in determining this rate. Metcalf, BPA, E-BPA-32, 53.

The California parties argue that the Spill rate is too high because it is not consistent with cost-of-service principles. LADWP and PG&E recommend that a suitable proxy for the cost of service is the total average cost of FBS hydroelectric resources plus a transmission charge, since spill energy is produced exclusively by hydro resources. Parmesano, LADWP, E-LA-01, 3-4; Buckingham, PG&E, E-GA-01, 4-5, 7.

SCE and CPUC recommend alternative Spill rates that are based on marginal cost. SCE proposes a rate based on an average hydro O&M cost, a transmission charge, an adder for unquantifiable costs and an incentive. Lindsay, SCE, E-CE-01, 8; Reply Brief, SCE, R-CE-01, 33-34. CPUC recommends a Spill rate based on the marginal cost of spill energy plus a premium, the level of which depends on the guarantee. Transmission costs are calculated and charged separately. Mattson, CPUC, E-CP-01, 13-16; Reply Brief, CPUC, R-CP-01, 14.

LADWP and SCE object to rounding the average coal plant variable cost from 12.89 to 13.0 mills/kWh. LADWP states that the rounding is unreasonable and SCE concludes that the savings in administrative costs due to rounding are far less than the additional cost to the purchasers. Parmesano, LADWP, E-LA-01, 6; Lindsay, SCE, E-CE-01, 7-8.

Concerning the coal plant analysis, the WWPUD's recommend three changes. The first change is including Valmy-2 since it was included in the hydro regulation studies. The second change is to use the heat rate under minimum load conditions to convert fuel cost in $/MMBtu to mills/kWh. The third change is to use minimum output for weighting purposes to be consistent with the second change. Hutchison, et al., WWPUD, E-WW-01, 45-48.

LADWP recommends that Valmy-1 be excluded since it will be displaced with Standard rate energy. In addition, the weighting factor of variable costs should be the expected energy output under average water conditions of units which could be displaced. Parmesano, LADWP, E-LA-01, 5-6. SCE concurs that the weighting factor should use a measure of displaceable energy. Lindsay, SCE, E-CE-01, 7.

Finally, LADWP states that the variable cost data in the PNUCC Thermal Resources Database contain some fixed costs which should be excluded from the calculation. Parmesano, LADWP, E-LA-04R, 11-12.

Evaluation of Positions

All California parties assert that the Spill rate is too high because it is not consistent with cost-of-service principles. They argue that the Spill rate should be based on the cost of resources that produce spill energy, namely, hydro resources cost. Parmesano, LADWP, E-LA-01, 3-4; Buckingham, PG&E, E-GA-01, 7; Lindsay, SCE, E-CE-01, 8; Mattson, CPUC, E-CP-01, 13.

BPA agrees that the Spill rate is not based on cost; the Spill rate is set at a level below the cost of nonfirm energy (the Standard rate) in order to reflect marketing constraints such as limited transmission capability. It is the aggregate effect of the operation of the hydro facilities and thermal resources, and the availability of substantial storage that produces nonfirm energy. LADWP agreed that hydro spill energy may be available as a result of the earlier operation of thermal resources. Parmesano, LADWP, TR 7088. Also, no evidence was presented to substantiate the assertion that thermal plants would not be running during spill conditions. Thermal plants (e.g., nuclear) whose variable costs are less than the Spill rate may run concurrently with Spill rate sales.

In discussing the effect of nonfirm energy prices on Pacific Northwest resource planning, the NWU states "Although the market for nonfirm energy does not affect the amount of resource acquired, it is a crucial determinant of the types of resources selected. The choice of high-capital-cost/low-production-cost resources have been made consciously, in the expectation of nonfirm revenues recovering a portion of fixed costs. The high fixed costs were incurred in order to enable production at low variable costs . . . ." Schultz, NWU, E-NW-25R, 4. The decision to build Pacific Northwest baseload thermal resources is an important factor directly influencing the availability of nonfirm energy. Contrary to SCE's conclusion that the cost of spill energy is small since it will either be sold or wasted, Lindsay, SCE, E-CE-01, 6, the cost of spill energy is relatively high, but its marketable price at the time of spill conditions is lower than its cost.

SCE and CPUC argue that the Spill rate should be based on variable cost (or short-run marginal cost) of hydro generation. Mattson, CPUC, E-CP-01, 13; Lindsay, SCE, E-CE-01, 8. BPA variable costs are low at all times because it is low variable-cost baseload thermal generation that complements the hydro system. The Pacific Northwest planned such a system to enable production at low variable cost. Schultz, NWU, E-NW-25R, 4. Regardless of the condition of the FCRPS and the nonfirm energy market, the cost of the nonfirm energy remains fixed. LADWP agreed that the cost of hydro generation does not change during a spill condition, Parmesano, LADWP, TR 8690; nor does the cost of nonfirm energy.

BPA does not set any rates based on short-run marginal costs. Nevertheless, if BPA were to set the Spill rate on the short-run marginal cost, it is true that the short-run generation cost to society may be lower than the generation component of the Spill rate because of the inability to store the energy. However, the incremental transmission cost to society may be substantially higher than the transmission component of the Spill rate due to shortage costs. LADWP stated that a transmission shortage cost is a component that would properly be included in a rate based on short-run marginal cost if the full capacity on the transmission system is utilized. Parmesano, LADWP, TR 8702. When the Spill rate is in effect, the Southwest Intertie is normally used to its full capacity. Since no study of these shortage costs has been performed, it is not clear whether the short-run marginal cost of nonfirm energy is greater or less than the Spill rate.

LADWP argues that BPA could avoid imposing shortage costs on other customers by merely interrupting nonfirm service to the customer whose use would cause the shortage. Therefore, it is argued that the notion of shortage costs as a component of short-run costs is not applicable to nonfirm sales. Reply Brief, LADWP, R-LA-01, 19. However, when the Intertie is full and BPA is in a spill condition, there are customers in California who would be able to displace expensive thermal generation but for the lack of Intertie capacity. Thus, every purchase over the Intertie at full capacity, whether firm or nonfirm, denies that capacity to another willing purchaser. Thus, as LADWP states, "It is a portion of the short run marginal cost to society." Parmesano, LADWP, TR 8702.

LADWP's Spill rate proposal is the average hydro cost per kilowatthour plus a transmission component (the IR-83 energy charge). LADWP argues that this transmission component is appropriate because there are no transmission capacity costs associated with spill energy that is totally interruptible. Parmesano, LADWP, E-LA-01, 4. SCE also proposes to use the IR-83 energy component in their alternative Spill rate but offers no justification. Lindsay, SCE, E-CE-01, 8. LADWP's reasoning totally ignores the fact that the Southwest Intertie was partially justified on the basis of nonfirm energy transactions. All nonfirm energy sales to the Pacific Southwest use the Southwest Intertie and, during spill conditions, intertie capacity may increase in value because it limits the amount of sales that can be made. That is, there may be opportunity costs in the form of shortage costs associated with Intertie use. Parmesano, LADWP, TR 7078-7080, 8702. The use of the IR-83 rate which is available for wheeling of firm power between points within the Pacific Northwest region and specifically excludes Intertie wheeling cannot appropriately reflect the cost of transmitting nonfirm energy.

The CPUC proposes that BPA set the Spill rate at the marginal cost of spill energy plus a premium. This would be consistent with California policy in regard to purchasing power from qualifying facilities during hydro spill conditions under PURPA 210. In California, the price is reduced to zero if utilities continue to spill water. This policy is consistent with avoided costs and efficient utilization of resources. Mattson, CPUC, E-CP-01, 13-14. There is little relationship between purchases under PURPA 210 and inter-utility nonfirm energy sales. In addition, there is no evidence that the alternative Spill rate proposal of the CPUC would allow for a more efficient resource utilization than BPA's proposal. Based on experience under the current NF-2 rate, BPA altered the structure of the nonfirm energy rate to include the Displacement rate in order to assure maximum displacement of thermal resources. Metcalf, BPA, E-BPA-32, 53.

LADWP and SCE object to BPA's determination of a Spill rate of 13.0 mills/kWh when the analysis of the average coal plant variable cost is 12.89 mills/kWh. They consider this rounding unreasonable, and more costly to the purchasers than is justified by the savings of BPA administrative costs. Parmesano, LADWP, E-LA-01, 6; Lindsay, SCE, E-CE, 7-8. However, BPA did not use the coal plant analysis to directly determine the Spill rate. It was only one factor that BPA considered. BPA included the Displacement rate in the NF-83 initital proposal to allow BPA to displace thermal plants and recover adequate revenue. The coal plant analysis was an indication of the displaceable cost of Pacific Northwest thermal plants. BPA also considered the significant Pacific Southwest nonfirm market and the effect of the Spill rate level on that market and on BPA revenue. BPA adopted the average coal plant variable cost as a guideline for setting the Spill rate in order to increase revenue over the revenue that BPA would receive using the same method as for the current NF-2 rate, and allow for some displacement of Pacific Northwest thermal plants at the Spill rate. Metcalf, BPA, E-BPA-32, 53; Metcalf, BPA, TR 5453, 5493, 5464-5467.

The first change to the coal plant analysis that the WWPUD's recommend is the inclusion of Valmy-2. Their reasoning is that this plant was included in the hydro regulation studies and would have an effect on the amount of available nonfirm energy in the test year. Hutchison, et al., WWPUD, E-WW-01, 46. Regardless of whether Valmy-2 affects the amount of nonfirm energy, BPA's focus in this analysis is the displaceable cost of Pacific Northwest thermal plants. The on-line date for Valmy-2, as reported in the PNUCC Thermal Resources Database, is September 1985. Thus, this resource would not be available to displace with nonfirm energy during the 20-month rate period. However, in cross-examination, the WWPUD's reported that Valmy-2 is expected to come on-line in June 1985, according to the Western Systems Coordinating Council (WSCC). Schneider, WWPUD, TR 6470. At best, BPA would be able to displace this resource only in the last month of the rate period.

In another comment concerning the list of coal plants included in the analysis, LADWP recommends excluding Valmy-1, since it will be displaced with Standard rate energy and would not be operating during the spill period. Parmesano, LADWP, E-LA-01, 5. Although this is true, BPA would still be selling nonfirm energy at the Spill rate for displacement of Valmy-1. Plant operators would substitute Spill rate energy for Standard rate energy.

The WWPUD's point out that BPA incorrectly used the heat content to convert the variable fuel cost from dollars per million BTU to mills/kWh instead of using the heat rate. Hutchison, et al., WWPUD, E-WW-01, 46-47. BPA recognizes this error and the analysis has been corrected. In addition to this change, the WWPUD's recommend using the heat rate under minimum load conditions. Their reasoning is as follows. The Spill and Displacement rates will be in effect when the FCRPS is spilling or forecast to spill. The owners of coal plants will likely have their own nonfirm energy so that the coal plants will be operating below maximum load levels and optimum heat rates. "Inasmuch as the Displacement rate is designed to allow for a plant to be completely shut down, we believe that it is appropriate to use the heat rate at a point of minimum generation where a decision must be made to either shut the plant down or keep it running." Hutchison, et al., WWPUD, E-WW-01, 47-48. It is not clear that a plant is necessarily operating at the minimum load level when the Spill rate is offered. If the variable cost of the plant is less than the Standard rate, the plant may be operating above minimum generation level when the Spill rate is offered. Indeed, the variable cost may be lower than the Spill rate, so that even when Spill rate energy is offered, the plant will continue to operate -- not necessarily at minimum levels. It is appropriate to use the heat rate value that corresponds to a load level at about the midpoint of the heat-rate curve because it appears that the coal plants may be operating at different levels, depending on their variable costs and market conditions.

The WWPUD's also recommend that the weighting factor should be the minimum capacity instead of the maximum the BPA used in order to be consistant with their calculation of the variable cost. Hutchison, et al., WWPUD, E-WW-01, 48. LADWP's recommendation for the weighting factor is the expected energy output under average water conditions of units which could be displaced. Parmesano, LADWP, E-LA-01, 5. SCE agrees that the weighting factor should use a measure of displaceable energy. Lindsay, SCE, E-CE-01, 7.

The capacity output appears to be a stable figure that reflects on the operational characteristics of the plant. The energy output of a plant is affected by many variables, e.g., the economic situation, maintenance, and forced outages; however, it may give a more accurate measurement of displaceable energy. Neither method appears clearly superior although the capacity weighting would remain relatively stable over time unlike the energy weighting.

LADWP determined that some of the variable cost data from the PNUCC Thermal Resources Database contains some fixed costs. Parmesano, LADWP, E-LA-04R, 11-12. BPA agreed to make adjustments in the coal plant analysis if convinced that there were fixed cost included in the variable cost components. Carr, BPA, TR 5507. Through data requests of the coal plant owners, LADWP received information about the specific cost components in the PNUCC data and it appears that some fixed costs are included in the variable cost data. The WWPUD's argue that costs of wheeling and transmission losses should be considered in determining the incremental cost of power. Mundorf, WWPUD, TR 5611-5616.

It is necessary to reexamine the appropriate level of the Spill rate based on the change in its application. Because BPA will not automatically implement the Spill rate during spill conditions, the goal of revenue enhancement is no longer as important as for the initial proposal. It is also not necessary that the Spill rate be set below the incremental cost of thermal plants because of the existence of the Displacement rate. It is necessary that the Spill rate allow BPA to widen its market and, in conjunction with the Displacement rate, achieve maximum economic thermal displacement. A Spill rate designed in the same manner as the NF-2 Spill rate, at the lower end of the decremental cost of Pacific Northwest coal plants, will accomplish those objectives.

Decision

The coal plant analysis has been revised to remove the variable O&M costs specifically identified by LADWP. Based upon that revised analysis, the Spill rate is set at 11 mills/kWh which corresponds to the lower end of the Pacific Northwest coal plant variable costs. A surcharge of 1.8 mills/kWh will be added for guaranteed delivery. This rate will enable BPA to widen its market by displacing some Pacific Northwest thermal with the Spill rate. Lower cost Pacific Northwest thermal may continue to run if used to serve firm load (unless the Displacement rate is offered) but this lower Spill rate should discourage these plant owners from competing with BPA if their plants are surplus to the utility's firm load requirement. It may not be economically advantageous to sell this surplus thermal at the Spill rate when other factors, such as wheeling costs, are considered. In a situation where BPA has enough nonfirm energy to displace all Pacific Northwest thermal generation, the Displacement rate will accomplish that displacement.

g. Displacement Rate

BPA proposed adding a Displacement rate to the NF-83 rate. The Displacement rate would be effective when BPA had more nonfirm energy than could be sold at the Spill Rate. The inclusion of the Displacement rate ensures that BPA displaces the greatest amount of thermal generation and increases BPA's NF-83 revenues.

Issue #1

Should BPA institute a Displacement Rate in the NF-83 rate schedule?

Summary of Positions

In the initial proposal, the Displacement rate was proposed to apply to sales of nonfirm energy when excess energy existed on the FCRPS above available markets at the Spill rate. It was a share-the-savings rate equal to one-half of the sum of the purchaser's decremental cost of generating or acquiring power from alternative resources and BPA's incremental cost of supplying the energy. The Displacement rate, in combination with the Spill rate, would allow BPA to displace the maximum amount of thermal resources while increasing revenues compared to the NF-2 rate design. Metcalf, BPA, E-BPA-32, 53.

All California parties object to instituting a Displacement rate in the NF-83 rate. LADWP charges that the rate is discriminatory and objects to the use of the purchaser's cost instead of BPA's costs as the basis for price. Parmesano, LADWP, E-LA-01, 1-3. PG&E also charges that the Displacement rate is discriminatory. Buckingham, PG&E, E-GA-01, 5.

SCE contends that the Displacement rate exceeds the cost of service and, therefore, violates the requirement that rates be fixed at the lowest possible cost to consumers. In addition, the rate is discriminatory. Lindsay, SCE, E-NE-01, 6-7.

The CPUC argues against the Displacement rate for 4 reasons: (1) it unreasonably increases the premium above cost while accomplishing the goal of displacing Pacific Northwest thermal; (2) institution of the rate demonstrates that the Spill Rate is too high for efficient use of resources; (3) it segments the market; and (4) it is not justified on the basis of BPA's marginal costs, equitable distribution of costs, efficient use of resources or other BPA ratemaking considerations. Mattson, CPUC, E-CP-01, 17.

California parties continue to argue in reply briefs that the implementation of the NF-83 rate schedule may lead to discriminatory treatment of nonregional customers. Reply Brief, PG&E, R-GA-01, 11-12; Reply Brief, LADWP, R-LA-01, 9-10; Reply Brief, SCE, R-CE-01, 25-28; Reply Brief, CEC, R-CC-01, 13-14; Reply Brief, SDG&E, R-SD-01, 4.

The NWU's support BPA's use of a share-the-savings rate as a downward departure from the Standard rate. Schultz, NWU, TR 6752. The DSI's assert that the Displacement rate will not result in unlawful discrimination. Opening Brief, DSI, B-DS-01, 96-97.

Evaluation of Positions

LADWP contends that the Displacement rate is inconsistent with cost-of-service principles as well as the cost-of-service standard adopted by BPA pursuant to PURPA. Parmesano, LADWP, E-LA-01, 3. These arguments are addressed in Sections (1) and (2).

LADWP also referred to James C. Bonbright's Principles of Public Utility Rates as a standard ratemaking textbook which identifies cost-based rates as a goal of ratemaking. Parmesano, LADWP, E-LA-01, 1-2. The ICP cited passages of this book that discussed (1) the flexibility of the cost-of-service standard which contributes to its popularity; and (2) the contention that value should also be taken into consideration in ratemaking. Wood, ICP, TR 7084-7086. However, LADWP responded that there were two major reasons for cost estimates to vary: first, there are two basic cost concepts (average embedded cost and marginal cost) that can reasonably be used to design rates; and second, underlying ratemaking assumptions may vary. In addition, LADWP states that Bonbright does not endorse value of service ratemaking. LADWP does not think that BPA's situation would meet any of the three special requirements which Bonbright states may be justification for value-of-service pricing. Parmesano, LADWP, E-LA-04R, 3-8.

BPA's Spill and Displacement rate sales conform to the first two requirements that are justification for value-of-service pricing. First, Bonbright describes a situation in which a utility is unable to earn a fair rate of return for reasons of competition or a decline of prosperity in the community. BPA is in such a situation when it is forced to lower the NF-83 Standard rate (to the Spill or Displacement rate) during a spill condition due to competition. The nature of the competition is that there is far more energy than market available due to transmission constraints. It is appropriate, therefore, for BPA to incorporate value of service in its Nonfirm Energy rate to minimize the revenues lost because of this competition. No purchaser is harmed or discriminated against because the NF-83 rate will never be greater than the cost-based Standard rate; the Displacement rate which is based on the purchaser's decremental cost is capped by the cost-based Standard rate.

The second use of value-of-service pricing Bonbright describes is the pricing of different products based on the differences in the price elasticities for them. This pricing is defensible on the ground that it is a means of making good a deficiency in total revenue that would result from the sale of all public utility services at marginal or out-of-pocket costs. LADWP states that BPA's marginal costs would produce too much revenue, and furthermore BPA has not determined relative elasticities of its customer classes. Parmesano, LADWP, E-LA-04R, 6. However, LADWP fails to consider that the Spill and Displacement rates are a reduction from the embedded cost-based Standard rate and will provide BPA with only a portion of the embedded cost of nonfirm energy. Both the Standard and Spill rates will exceed BPA short-run incremental cost of generating electricity during spill periods, which all parties agree is very low. In regard to determining customer elasticities, LADWP concedes that the decremental costs of purchasing utilities could be used as a proxy for elasticities of demand. Parmesano, LADWP, TR 8705-8706. The Displacement rate uses the decremental cost of the purchasing utilities in order to assure that all economic displacement will occur while minimizing the difference between the rate charged and average cost of service. Thus, the NF-83 rate uses a value-of-service pricing mechanism only when market conditions will not allow recovery of the full cost of nonfirm energy. In no case will the NF-83 rate be greater than the cost-based NF-83 Standard rate.

All California parties charge that the Displacement rate is discriminatory because different buyers pay different prices for the same service. BPA is segmenting the market and extracting the consumer surplus from each customer group. Parmesano, LADWP, E-LA-01, 3; Buckingham, PG&E, E-GA-01, 5; Lindsay, SCE, E-CE-01, 7; Mattson, CPUC, E-CP-01, 17.

In reply briefs, PG&E argues that the proposal to sell Displacement energy discriminates against California utilities because it can occur on a "selective and discretionary basis." Reply Brief, PG&E, R-GA-01, 11. PG&E argues that the product offered under all three NF 83 rate schedules is nonfirm energy; the restrictions on the availability of the three are arbitrary. Reply Brief, PG&E, R-GA-01, 12. LADWP suggests that unless each customers pays approximately the same average price for nonfirm energy, the rate is discriminatory. Reply Brief, LADWP, R-LA-01, 9-10. SCE argues that scheduling discretion may lead to discriminatory treatment of nonregional customers if BPA adopts a strategy of offering two rates for the same service to two separate customer groups. Reply Brief, SCE, R-CE-01, 25-28. CEC also argues that the Displacement rate results in a windfall to Northwest parties at the expense of California parties. Reply Brief, CEC, R-CC-01, 13-14.

However, it is not true that Displacement and Spill rate energy are precisely the same product. BPA does not place restrictions on the use of Spill rate energy but does place restrictions on the use of Displacement rate energy. For example, Spill rate energy may be used to displace a firm resource or a nonfirm resource. Displacement rate energy may only be used to displace a specific generating resource or a specific displaceable firm purchase. Dean, BPA, E-BPA-33, 5-6. The restriction on Displacement rate sales is in recognition of one of the major goals of the NF-83 rate design -- to displace thermal resources. The Displacement rate allows BPA to displace the maximum amount of thermal generation even when the decremental cost of the thermal generation is below the average cost of nonfirm energy.

Even if the product sold at the Displacement rate were essentially the same as that sold at the Standard or Spill rate, simultaneous sales do not constitute undue discrimination. As the NWU's point out, ". . . there is no principal in ratemaking which prevents a utility from selling below its cost-based rate to salvage some revenue from what would otherwise be a total loss of revenue." Schultz, NWU, TR 6752. The California proposal that consideration of the purchasing utility's decremental cost should never be used in pricing nonfirm energy would leave BPA with a dilemma during spill periods. BPA must either sell all its nonfirm energy at rates far below average cost or it must spill energy because the fixed rate is too high to displace thermal plants. (Even the low Spill rates proposed by the Californians may be too high to displace some thermal.) The Displacement rate solution, which salvages some revenues from energy which would otherwise be spilled, benefits all BPA customers including other nonfirm customers through the crediting of those revenues in the calculation of the Standard rate.

NWU's conclude that the Displacement rate is consistent with the guidelines for the 1979 H-6 Nonfirm Energy rate in the FERC Order Confirming and Approving Rates on a Final Basis (see Issue #1 for a discussion of the FERC Order). The DSI's assert that the Displacement rate is not inequitable or discriminatory because the rate would be available under the same conditions to all BPA puchasers. Opening Brief, DSI, B-DS-01, 96-97. The NWU's state that the NF-83 rate is not inequitable to PSU utilities because the Standard rate is lower than a share-the-savings rate based on half the current cost of oil or gas-fired generation. Therefore, it is lower than a share-the-savings rate which is designed to equally share the benefit of a typical sale from Northwest to Southwest. The NWU's assert that the loss of the existing Southwest Intertie would be a greater burden to California than the Pacific Northwest. Schultz, NWU, E-NW-25R, 4-6.

Decision

BPA is instituting a Displacement rate in the NF-83 rate schedule to accomplish the primary goals of the NF-83 rate -- displacement of thermal generation and increased revenue recovery. The Displacement rate is not discriminatory. The Displacement rate includes two fixed rates to allow BPA to displace (1) coal-fired resources and end-user alternate fuel loads; and (2) nuclear generation. Fixed rates were chosen to facilitate administration of the Displacement rate. The availability criterion is being changed to allow the Displacement rate to be offered in spill or forecast spill conditions, regardless of whether the Spill rate has been implemented.

Issue 2

What is the appropriate design for the Displacement rate?

Summary of Positions

The initial proposal Displacement rate was a share-the-savings rate equal to one-half of the sum of the purchaser's decremental cost of generating or acquiring power from alternative resources and BPA's incremental cost of supplying the energy. Metcalf, BPA, E-BPA-32, 53.

SCE argues that the share-the-savings rate structure is inappropriate for pricing energy that is moving in only one direction. Lindsay, SCE, E-CE-01, 6-7.

PG&E contends that a share-the-savings rate would not substantially change the pricing of non-BPA power during nonspill conditions and nonfirm energy availability would not increase. Buckingham, PG&E, E-GA-02R, 2-3. They also assert that a share-the-savings rate may reduce expected revenue. Buckingham, PG&E, E-GA-01, 5. LADWP argues that BPA's NF-83 revenues could be significantly reduced with a share-the-savings rate since the price to Pacific Northwest customers will be well below the Standard rate. Parmesano, LADWP, E-LA-04R, 9.

The NWU's argue that the Displacement rate capped by the Standard rate is less than a share-the-savings rate. They observe that many share-the-savings rates are currently used around the country. Schultz, NWU, E-NW-25R, 4-6.

The PGP proposes that BPA should adopt a Displacement rate as its only NF-83 rate. This share-the-savings rate is a two-part rate to account for differences in variable costs between the Pacific Northwest and Pacific Southwest. The rate would equal half of the total of the BPA incremental cost and the average decremental cost for the Region of the type of plant being displaced. This Displacement rate would be capped at the Standard rate. Opening Brief, PGP, B-PG-01, 25-27; Garman, et al., PGP, E-PG-06R, 16-19.

BPA discussed an alternative to the share-the savings Displacement rate in which the Spill rate would be eliminated and a coal and nuclear Displacement rate would be set at a level to displace coal and nuclear plants. Pollock, BPA, E-BPA-15, 14.

Evaluation of Comments

The NWU's state that share-the-savings rates are fairly common in the United States, e.g., the Western Systems Coordinating Council's Brokering Scheme and the transactions among utilities of the Florida Power Pool. The Florida Power Pool whose transactions take place at a straight share-the-savings rate is hailed by regulators and other government officials as a model. Schultz, NWU, E-NW-25R, 5.

SCE's argument that share-the-savings rates are not appropriate for pricing energy that is moving in only one direction overlooks the fact that the Displacement rate is capped below the embedded cost-of-service. Thus, all customers are protected from paying a rate above the cost of service.

PGP's alternative NF-83 rate proposal is a variation on BPA's proposal eliminating the Spill rate. PGP proposes a Displacement rate capped by a Standard rate. Their share-the-savings Displacement rate is a two-part rate to account for differences in variable costs between the Pacific Northwest and Pacific Southwest. The Displacement rate would be equal to half the sum of the BPA incremental cost and the average decremental cost for a region of the type of plant being displaced. The design of this rate is intended to address the California parties' claim that a share-the-savings rate design is discriminatory because different rates are charged for the same service. Thus, two incremental costs are provided for Pacific Northwest sales and two are provided for Pacific Southwest sales that reflect the variable cost of the type of plants to be displaced. These reflect the variable cost of intermediate and high cost thermal plants for each region. PGP asserts that "Share the Savings is a rate which allows BPA to react to water and market conditions and insures maximum displacement of thermal resources inside and outside the region. It is the rate which provides the greatest benefits to the selling and purchasing agencies, insures the greatest amount of nonfirm sales and revenues to BPA, and is the best alternative from an environmental consequences standpoint. The flexibility of the share the savings rate also allows the maximum use of the generation capability of the river system." Garman, et al., PGP, E-PG-01, 63; Garman, et al., PGP, E-PG-06R, 16-17; Opening Brief, PGP, B-PG-01, 25-29.

The PGP's proposal differs from BPA's proposal to eliminate the Spill rate in that the Displacement rate is offered during all operating and marketing conditions and not just during spill or imminent spill conditions. LADWP states that BPA's NF-83 revenues may significantly decline because nonfirm prices to Pacific Northwest customers will be well below the proposed Standard rate and often below the proposed Spill rate. Parmesano, LADWP, E-LA-04R, 9. Because a nonfirm revenue analysis on the PGP's proposal has not been performed, it is difficult to assess the effect of the rate design on revenues. A lower nonfirm rate for Pacific Northwest customers than the Standard rate during nonspill conditions may result in increased sales. However, since the amount of available nonfirm energy is limited when the FCRPS is not spilling, the only effect may be, in fact, a decrease in revenue.

Incorporating a relatively fixed Displacement rate would significantly ease administration of the rate. The proposal by BPA to set fixed Displacement rates for coal and nuclear plants also allows for greater administrative ease and gives purchasers a greater ability to plan their operations.

Decision

The share-the-savings Displacement rate is opposed by California parties who charge that such rate forms are discriminatory because different customers pay different rates for the same product. However, share-the savings rates are a commonly accepted rate form in the United States and are clearly not discriminatory. The Displacement rate would be offered to all customers on the same basis. BPA's adaptation of the share-the-savings principle to the Displacement rate ensures that purchasers whould never pay a rate greater than the cost-based Standard rate regardless of the purchaser's decremental cost. However, BPA responded to a Pacific Northwest proposal to fix the Displacement rate for purposes of administrative ease. All purchasers operating a generic type of resource will pay the same rate to displace the resource.

An examination of the decremental cost of thermal plants indicated that Displacement rates of 7 mills/kWh for coal and 3 mills/kWh for nuclear would achieve maximum thermal displacement. An additional 1.8 mills/kWh will be charged for guaranteed nonfirm energy to displace coal-fired thermal generation. Because the displacement of nuclear plants requires a guaranteed availability of energy and the incremental cost of nuclear generation is very low, BPA will not assess the 1.8 mills/kWh charge for guaranteed service to displace nuclear plants. The Standard rate or Spill rate will displace oil- and gas-fired generation.

Issue #3

What terms and conditions should apply to the Displacement rate?

Summary of Positions

In the NF-83 rate proposal with the 13.0 mills/kWh Spill rate, BPA limited the Displacement rate to resource costs less than 15 mills/kWh (the Spill rate plus 2 mills/kWh). Displacement rate sales would not be made to a customer who can save at least 2 mills/kWh when displacing a resource through a Spill rate purchase. Metcalf, BPA, E-BPA-32, 53. BPA also stated that Displacement rate sales will not be made if such deliveries are expected to reduce BPA's other sales. Dean, BPA, E-BPA-33, 6.

The NWU's argue that the Displacement rate should be available to all customers whenever offered. Otherwise, a large discontinuity in pricing is created that is detrimental to the administration of the rate. When buying Displacement rate energy, a purchaser should not be allowed to displace another BPA purchase or any Southern Intertie delivery made under the Exportable Agreement, regardless of source. The NWU's also argue that displaced thermal should be shut down. Schultz, NWU, E-NW-07, 7-9. The DSI's, Congressman Weaver, and the CEC concur that displaced thermal should be shut down. Mizer, DSI, E-DS-13, 6; Meek, Weaver, TR 5569, 5658; Opening Brief, CEC, B-CC-01, 41-44. PGP, in reference to its alternative Displacement rate, states that plants should be backed off to a level equal to the amount of nonfirm purchased. Opening Brief, PGP, B-PG-01, 27. LADWP states that BPA is unclear on how the Displacement rate would be implemented, particularly in regard to the requirement on shutting down thermal plants. Parmesano, LADWP, E-LA-04R, 12. SCE argues that BPA's decision not to offer Displacement rate energy to displace economy energy purchases ignores market reality. Opening Brief, SCE, B-CE-01, 43.

The CEC contends that the share-the-savings rate form is inconsistent with BPA's goal of generating more nonfirm energy revenues. They argue with BPA's application of Pub. L. No. 88-552 which would exclude the Pacific Southwest from purchasing Displacement rate energy until Pacific Northwest demand for such energy was filled, regardless of price. They assert that the rate is a windfall for customers who make Displacement rate purchases; it gives incentive to eligible customers to play a waiting game; and it provides customers an incentive to stretch the facts to insure decremental costs below 15 mills/kWh. The CEC presents an alternative Displacement rate structure to remedy the perceived inadequacies. Opening Brief, CEC, B-CC-01, 45-52 and 63-64.

LADWP states that it is unclear how the Displacement rate would work if the Spill rate were eliminated. Specific concerns are: (1) the conditions under which Displacement rate energy will be made available; and (2) requirements vis-a-vis resource displacement. An inefficient use of resources may result if a resource must be displaced. Parmesano, LADWP, E-LA-04R, 12-13.

Evaluation of Positions

The NWU's argue that BPA should employ a nondiscriminatory approach when offering Displacement rate energy. That is, the same rate should be offered to all customers, regardless of whether they had been purchasing energy at the Spill rate or Standard rate. BPA's proposal creates a large discontinuity in price. When the decremental cost is close to the 15.0 mills/kWh cap, or to the Standard rate (if the Spill rate is eliminated), the NWU argues that BPA can expect disputes over the decremental cost, which would be detrimental to the administration of the rate. NWU's acknowledge that BPA's logic may be theoretically valid, but it is not practical operationally. Schultz, NWU, E-NW-07, 8, 9.

Although the NWU's state that their method of administering the Displacement rate would have the same effect under most conditions as BPA's, it appears that BPA would actually collect less revenue. BPA's nonfirm energy revenue forecast assumes that the Displacement rate sales will only augment

Spill rate sales (or Standard rate sales), not displace them. For example, if all Spill rate (11 mills/kWh) sales are converted to Displacement rate sales, displacement of any resource with a decremental cost of less than 20 mills/kWh would result in a Displacement rate sale at less than the Spill rate. If Displacement rate sales were allowed to displace Standard rate sales, the revenue loss would be greater and more frequent. It is true that disputes may arise over the reported decremental cost, but that is expected to some extent in the administration of this rate form.

The NWU's, DSI's, Congressman Weaver, PGP, and CEC support a shutdown rule when BPA markets Displacement rate energy. Schultz, NWU, E-NW-07, 7-9; Mizer, DSI, E-DS-13, 6; Meek, Weaver, TR 5569, 5658; Opening Brief, CEC, B-CC-01, 41-44; Opening Brief, PGP, 8-PG-01, 27. The CEC argues that because BPA has no clear shutdown rule, a Pacific Northwest utility with no excess thermal generation could use BPA's Displacement rate energy to compete with BPA California sales. The Pacific Northwest utility would purchase Displacement rate energy, use it to replace its operating thermal generation, and market the thermal generation to California at just under the BPA nonfirm energy price. If California buys such energy, it will displace BPA energy on the Intertie and increase BPA's spill. CEC recognizes BPA's rule that Displacement rate sales will not be made if expected to reduce BPA's other sales; however, they contend that this rule is unenforceable. Opening Brief, CEC, B-CC-01, 41-44.

BPA formulated this rule because there are circumstances under which it would not be to the benefit of ratepayers to have the resource shut down. As an example, BPA explained that it would be in the interest of the utilities and ratepayers to have Colstrip continue to run if it could displace oil-fired generation in Montana to serve loads which were outside of BPA's market. Dean, BPA, TR 5655-5656. BPA recognizes that a rule requiring shutdown of resources may be easier to police than the rule BPA has developed. The Hearing Officer proposed a rule that requires shutdown except under specific circumstances that could allow for less burdensome administration and avoid situations described above in the Colstrip example. Wenner, TR 5659-5660.

The NWU's recommend that a purchaser of Displacement rate energy be prohibited from claiming as a displaced resource another purchase from BPA or any Southern Intertie delivery made under the Exportable Agreement, regardless of source. Schultz, NWU, E-NW-07, 9. When BPA is in a spill condition, most of the energy delivered to California on the Intertie is nonfirm energy. BPA will not offer Displacement rate energy to displace a nonfirm purchase from another utility. Dean, BPA, E-BPA-33, 5-6; Dean, BPA, TR 5751.

SCE argues that the condition cited above for selling Displacement rate energy ignores the market reality that utilities decide to make nonfirm purchases based on all opportunities available. SCE points out that 30 to 35 percent of its load is supplied through purchased power and 80 percent of its purchased power is economy energy. The Displacement rate requires that the rate to SCE be based on decremental costs of more expensive generation resources. Opening Brief, SCE, B-CE-01, 43. The displacement of thermal resources is a major factor in designing the NF-83 rate. BPA's intent in developing the Displacement rate is to displace thermal generation that cannot be displaced economically at the Spill (or Standard) rate. Dean, BPA, E-BPA-33, 4-5; Metcalf, BPA, E-BPA-32, 53. SCE's economy energy purchases allow them to displace high cost thermal with low cost purchases. BPA is seeking to displace additional thermal generation on a purchaser's system, not low cost economy energy. BPA is also attempting to avoid the situation in which a utility uses the price of nonfirm purchases on the Intertie as the decremental cost of power. In that case, the Displacement rate energy would not be an alternative to the existing nonfirm purchase over the Intertie, it would only be a means to reduce the transaction price.

The CEC argues that BPA's application of Pub. L. No. 88-552 would exclude the Pacific Southwest from purchasing Displacement rate energy until all Pacific Northwest demand was filled regardless of price. Opening Brief, CEC, B-CC-01, 50. BPA agreed that this would happen but explained: ". . . when we are selling at the displacement price, we are attempting to enlarge our market, and the probability or the number of times that we would be marketing at the displacement rate, and at the same time, having limiting supplies that we would have to allocate among various purchasers, either because of price or priority, would be almost nonexistent." Dean, BPA, TR 5674-5675.

CEC contends that the share-the-savings rate unnecessarily limits BPA revenue with no perceivable policy benefit. If the Displacement rate was set at a uniform 2 mills/kWh below the decremental cost of the displaced resource, BPA could avoid giving a windfall to Displacement rate customers. This design would also remove the incentive (1) for eligible customers to play a waiting game; and (2) to stretch the facts to insure a decremental cost below 15 mills/kWh. Another alternative would allow the Displacement rate to float down in half mill increments until all available spill energy is sold. BPA would allow customers to bid at each rate until all available power was sold. Opening Brief, CEC, B-CC-01, 46-49 and 63-64.

The role of the Displacement rate is to displace thermal generation which is not economically displaceable at the Spill rate. It is true that the alternative of setting the Displacement rate 2 mills/kWh below the purchaser's decremental cost would likely increase revenue over the initial rate proposal while displacing thermal plants. However, it would be difficult to administer and would give customers an incentive to report as low a decremental cost as possible. The second proposed alternative of the "floating" Displacement rate would add an incentive for all customers to play a waiting game, especially in a situation when there is more nonfirm energy than available market. It is unclear whether this proposal would be practical to implement.

Decision

Displacement rate energy will be offered when all markets have been satisfied at the Standard or Spill rate, whichever is in place. This proposal differs from the initial proposal in that Displacement rate sales will augment Standard rate sales as well as Spill rate sales. This change furthers BPA NF-83 goals of thermal displacement and increased revenue in light of the decision to retain the Spill rate. BPA will shift to the Spill rate from the Standard rate only when net revenues are projected to increase. When BPA is marketing Standard rate energy, there may be some additional lower-cost thermal resources that could be displaced at a lower rate. BPA will offer to displace such resources with Displacement rate energy to enlarge the nonfirm energy market. Thus, BPA will displace thermal resources and increase revenues.

The Displacement rate will be available to displace resources with incremental costs less than or equal to the sum of the Standard or Spill rate (whichever rate is in effect) plus 2 mills/kWh. Because of the fixed nature of the Displacement rate, the offer of Displacement rate energy to all nonfirm energy purchasers would result in a significant lowering of nonfirm energy revenues. The Displacement rate will augment nonfirm energy sales at the Standard and Spill rates, not displace them. The fixed rate will facilitate administration by not relying on purchasers reporting their decremental cost. The discontinuity is a result of the nature of the nonfirm market and the decremental cost of displaceable resources. This discontinuity is not unfair or discriminatory because the rules are the same for everyone and no customer will pay more than the cost-based Standard rate.

Displacement rate energy will be marketed to shut down or turn down identified generating plants which the purchaser owns and operates. This definition includes portions of generating plants from which the purchaser has the right to receive the variable output so that the purchaser is able to control the generation levels. BPA agrees with parties that resources should be shut down or backed down in an amount equal to the amount of Displacement rate energy purchased. This rule will be easier to administer and will ensure that the goal of thermal displacement will be achieved.

Issue #4

Does the degree of flexibility present in the Nonfirm Energy rate reduce purchasers' supply options?

Summary of Positions

California parties suggest that the implementation of the Nonfirm Energy rate restricts the supply options of purchasers. Reply Brief, PG&E, R-GA-01, 12; Reply Brief, SCE, R-CE-01, 20-22; Reply Brief, CEC, R-CC-01, 12.

Evaluation of Positions

PG&E suggests that BPA's motive in adopting the nonfirm rate structure "appears to be to induce entities that compete with BPA for nonfirm sales to California -- and who would otherwise have an incentive to undercut BPA's price -- to shut down or curtail their thermal resources." Reply Brief, PG&E, R-GA-01, 12. SCE contends that the Nonfirm Energy rate schedule and in particular the degree of discretion inherent in the schedule "creates a situation inconsistent with the public policy of the United States as enunciated in the antitrust laws." Reply Brief, SCE, R-CE-01, 20-21. SCE argues that BPA could, through Northwest displacement, eliminate a supply of inexpensive energy and thus force Southwest customers into buying from BPA at a higher price than otherwise would be obtainable. Reply Brief, SCE, R-CE-01, 21-22. CEC contends that excess Northwest thermal should compete with BPA spill sales if the Standard rate is in effect. Reply Brief, CEC, R-CC-01, 12.

BPA does not agree that offering the Displacement rate will result in a reduction in purchasers' supply options. It is difficult to evaluate the California position on this issue because of a lack of specific allegations. It is not a necessary consequence of BPA's offer of Displacement rate energy that Northwest or Southwest entities will accept the offer. Both Northwest and Southwest entities retain several options. For example, a Northwest utility with an operating coal plant could purchase Displacement rate energy from BPA and shut down the plant; or continue to run the plant and make sales in the nonfirm energy market. A Southwest utility could likewise displace a thermal plant with purchases of BPA nonfirm energy; or seek purchases within the Northwest or outside the Region. It remains probable that individual entities will ascertain under existing market conditions what actions to take. Dean, BPA, TR 5766.

Decision

The flexibility in the Nonfirm Energy rate does not result in limitations in the supply options of purchasers. The Displacement rate remains available to Southwest parties as with all other parties. The purpose of the Displacement rate, as it has been since the beginning of this rate process, continues to be the displacement of thermal resources. Dean, BPA, E-BPA-33, 4-5; Metcalf, BPA, E-BPA-32, 53; Prehearing Brief, BPA, P-BPA-01, 27. The displacement of thermal resources is the main result of the institution of a Displacement rate. The price of the Displacement rate reflects the variable costs of displacing particular resources. A lower price is required to displace coal and nuclear generation than is required for oil and gas. The Standard rate remains the cost-based rate for all nonfirm transactions, lowered as necessary to the Displacement rate to displace low-cost thermal resources.

Issue #5

Is the NF-83 Displacement rate consistent with Federal Energy Regulatory Commission orders and precedent?

Summary of Positions

SCE argues that the Displacement rate is inconsistent with FERC orders and precedent. Opening Brief, SCE, B-CE-01, 38-39; Reply Brief, SCE, R-CE-01, 18-19. LADWP, PG&E, and SCE argue that because the Displacement rate is a value-based rate, it is inconsistent with the Commission's Order Confirming and Approving System Rates on a Final Basis, 23 FERC 61,342 (1983). Opening Brief, LA/PG&E, B-LA/GA-01, 38; Reply Brief, PG&E, R-GA-01, 13-14. PP&L and the DSI's argue that the Displacement rate is consistent with the FERC order in question. Opening Brief, PP&L, B-PL-01, 44; Opening Brief, DSI, B-DS-01, 89.

Evaluation of Positions

LADWP and PG&E argue that the Displacment rate proposed by BPA is a type of value-based rate "condemned" by the Commission in the order approving BPA's 1979 rates. Opening Brief, LA/PG&E, B-LA/GA-01, 38. SCE makes a similar argument. Reply Brief, SCE, R-CE-01, 18. The Commission did not condemn value-based rates in that order, however, but only questioned whether BPA had fully supported its choice of the value-based H-6 nonfirm rate. In addition, the Commission suggested that BPA develop a fixed, cost-based nonfirm rate. The Standard rate is in harmony with that suggestion, as it is both fixed and cost-based. As discussed elsewhere, BPA departs from this fixed, cost basis only in the face of competitive market conditions.

If BPA is unable to recover the full costs of its nonfirm energy by selling at the Standard rate, BPA may resort to the Spill rate or Displacement rate in order to pursue the goals of maximizing revenues and displacing thermal resources. The fact that BPA uses the below-cost value-based Displacement rate in order to expand its market or to make the best of difficult marketing conditions comports with sound business principles. To adhere to the fixed, cost-based Standard rate in the face of adverse market conditions would jeopardize BPA's ability to repay it Federal obligation. This would be contrary to section 7(a)(2) of the Regional Act, which requires the Commission to find that BPA's rates yield revenues sufficient to repay the Federal investment over a reasonable number of years. 16 U.S.C. §839e(a)(2).

BPA's Displacement rate is designed, in part, to address a concern expressed by the Commission in the order approving BPA's 1979 rates; that is, that BPA's nonfirm rate "permit the maximum displacement of more expensive thermal resources both inside and outside the Pacific Northwest." 23 FERC at 61,744. It also seeks to remedy BPA's revenue underrecovery problem, a concern of the Commission discussed in its Order Confirming and Approving Rates on a Final Basis, 23 FERC 61,378.

In arguing that the Commission has rejected value-based rates, PG&E and SCE rely on the Commission's comment in the order approving BPA's 1979 rates that the term value-based pricing had "little rational basis." 23 FERC at 61,741. That comment, however, is applicable to the F-7 Seasonal Capacity rate, not the H-6 Nonfirm Energy rate. Nevertheless, assuming that the comment is applicable to nonfirm energy rates, there is clearly a rational basis for the Displacement rate. As discussed above, it is prudent for BPA to have available a rate lower than the Standard rate and Spill rate.

SCE cites <u>South Carolina Generating Company</u>, 16 F.P.C. 52 (1956), remanded for further proceedings, 249 F.2d 755 (4th Cir. 1957), <u>cert. denied</u> 356 U.S. 912 (1958) as containing a "vehement denunciation" of value-based pricing. Reply Brief, SCE, R-CE-01, 18-19. This case is inapplicable to BPA's nonfirm energy rates, however, as it was decided under the Federal Power Act.

<u>Decision</u>

The Displacement rate is consistent with Federal Energy Regulatory Commission orders and precedent.

h. <u>Procedural Considerations</u>

<u>Issue #1</u>

Do the NF-83 Spill rate and Displacement rate designs put forth in the Evaluation of the Record and the Record of Decision violate section 7(i)(4) of the Regional Act?

Summary of Positions

LADWP and PG&E argue that the Spill rate and Displacement rate designs put forth in the Evaluation of the Record constitute extreme departures from the originally proposed designs, such that the procedural safeguards of section 7(i) of the Regional Act have been violated, particularly section 7(i)(4). Reply Brief, LADWP, R-LA-01, 3; Reply Brief, PG&E, R-GA-01, 2-3.

Evaluation of Positions

Section 7(i) provides that the Administrator's final decision establishing a rate must be based on the "record which shall include the hearing transcript, together with exhibits, and such other materials and information as may have been submitted to, or developed by, the Administrator." 16 U.S.C. §839e(i)(5) (emphasis added). The development of refinements to the Nonfirm Energy rate design, such as those contained in the Evaluation of the Record and the Record of Decision, are contemplated by the Act. Moreover, as discussed below and in other portions of this decision, these refinements are based on, or can be reasoned to, from material contained in the record.

Section 7(i)(4) of the Regional Act provides that after a hearing the Administrator "may propose revised rates, publish such proposed rates in the Federal Register, and conduct additional hearings in accordance with this subsection." 16 U.S.C. §839e(i)(4) (emphasis added). The convening of an additional hearing is discretionary on the part of the Administrator. As is readily apparent from other portions of this decision which examine the evolution of the Nonfirm Energy rate, the changes made to the Spill rate and Displacement rate in this decision are not so significant as to require another hearing.

When taken to its logical conclusion, the position advocated by LADWP and PG&E produces an absurd result. On one hand, like all other parties, LADWP and PG&E advocate that the Administrator should change from the rates contained in the initial proposal. On the other hand, when the Administrator does make changes with which they disagree, such as those contained in the Evaluation of the Record, they advocate that he may not do so without convening another hearing. Taken to its logical conclusion, the Administrator would continue to have hearings *ad infinitum*, never reaching a final decision. Such a result would not only produce an absurd and unreasonable result, it would violate the requirement of 7(i)(5) that the "Administrator shall make a final decision . . . ." 16 U.S.C. § 839e(i)(5).

With respect to the Spill rate, the level has been lowered from 13 mills/kWh to 11 mills/kWh. A lower level for the Spill rate was advocated on many occasions by the California parties. Parmesano, LADWP, E-LA-01, 3-4, 6; Buckingham, PG&E, E-GA-01, 4-5, 7; Lindsay, SCE, E-CE-01, 7-8; Reply Brief, SCE, R-CE-01, 33-34; Mattson, CPUC, E-CP-01, 13-16; Reply Brief, CPUC, R-CP-01, 14. In addition, in order to increase BPA revenues and displace thermal resources, movement to the Spill rate is no longer required during spill or imminent spill conditions. The California parties argue that with this step BPA has drastically altered the Spill rate to the point of effectively eliminating it, and that such action constitutes a revision to the rate which requires an additional hearing. BPA disagrees.

The issue of the amount of revenues and thermal displacement which would occur with or without a Spill rate, and the issue of the appropriate design of the Spill rate was discussed extensively. The fact that a significant part of the hearing was focused on these issues was recognized by the Hearing Officer. See Order Denying Motion, WP-83-O-39, 1-5. See also Attachments B and C to Order Denying Motion (list of prefiled testimony on the elimination of the Spill rate and partial list of transcript references on the issue of the Spill rate). Moreover, BPA has retained the Spill rate in part in response to concerns raised by the California parties.

Earlier the California parties argued that elimination of the Spill rate would decrease BPA revenues because of competition, as well as reduce the amount of thermal resources displaced. Parmesano, LADWP, E-LA-01, 12; Buckingham, PG&E, E-GE-01, 9; McKenzie, PG&E, TR 9135-36; Chamberlain, CEC, TR 9170, 9175; Fairchild, CPUC, TR 9164-65. Based on these arguments BPA has retained the Spill rate for situations where its implementation would increase revenues and thermal displacement. Now the California parties are taking an position inconsistent with their earlier position, arguing that a retention of the Spill rate will result in less revenues. Reply Brief, PG&E, R-GA-01, 5-8; Reply Brief, SCE, R-CE-01, 20; Reply Brief, SDG&E, R-SD-01, 5. BPA, however, has forecast significant revenues from the Spill rate. FS-BPA-04, Appendix C, 23; FS-BPA-04A, Section D.

With respect to the Displacement rate, it now contains two fixed rates for the displacement of coal and nuclear plants which were not present in the initially proposed rates. Fixed rates along these lines, however, are based on the record. Pollock, BPA, E-BPA-15, 14. In addition, the fixed coal and nuclear displacement rates are designed to remedy the problem discussed in the record of determining the decremental cost of nonfirm energy purchasers. Dean, BPA, E-BPA-19, 6. Finally, the issue of whether the Displacement rate would accomplish its purposes, a purpose which has not changed from the initial proposal to the final rates, was discussed extensively throughout the record. Dean, BPA, E-BPA-33, 4-5; Metcalf, BPA, E-BPA-32, 53; Prehearing Brief, BPA, P-BPA-01, 27.

Decision

The changes to the Displacement and Spill rates contained in the Evaluation of the Record and the Record of Decision are firmly grounded in the record and are not so significant as to require an additional hearing pursuant to section 7(i)(4) of the Regional Act.

i. End-User Alternate Fuel Loads

Issue #1

Does the NF-83 rate provide for the displacement of loads which are presently being served with alternate fuels such as oil or gas?

Summary of Positions

The NF-83 Displacement rate in the initial proposal was directed at nonfirm energy markets which are unavailable at the NF-83 Spill rate when spill energy exists on the FCRPS. Dean, BPA, TR 5675. The rate is to be set at one half the sum of the purchaser's decremental cost plus BPA's incremental cost, provided the purchaser's decremental cost is less than the Spill rate plus 2 mills/kWh. BPA, E-BPA-7, 50-51. Displacement rate energy would be used for serving consumer loads with alternate fuel sources if the use of electricity is not economic at the Spill rate. Metcalf, BPA, E-BPA-32, 57.

The DSI's, APAC, and WWPUD's support the use of the Displacement rate for fuel displacement in dual fueled boilers. Mizer, DSI, E-DS-13, 15; Opening Brief, WWPUD, B-WW-01, 70-71; Cook, APAC, E-PA-08R, 19-20. APAC suggested that the rate be modified to apply specifically to industries displacing oil or gas production of steam and that it be set at one-half the market price for No. 6 fuel oil plus distribution handling charges. Engstrom, APAC, E-PA-7, 3-4.

Evaluation of Positions

The DSI's, APAC, and WWPUD's recommend that the Displacement rate be available for fuel displacement in dual fired boilers. The WWPUD's suggest that a bi-fuel boiler displacement market will substantially increase BPA's nonfirm energy market and assist BPA in minimizing the potential for spilling water during exceptionally good water conditions. It will also retain the value of nonfirm energy within the Pacific Northwest and reduce the use of the fossil fuels. Hutchison, et al., WWPUD, E-WW-02R, 32-33.

APAC points out that the availability of the Displacement rate for bi-fuel compatible boiler loads would not displace any other secondary markets or more valuable uses for the electricity. Such sales would be made only when BPA is spilling or cannot otherwise market the power at the Standard rate. APAC is seeking an explicit statement in the NF-83 Displacement rate that it will be available for these interruptible electric loads. Opening Brief, APAC, B-PA-01, 93-95; Engstrom, APAC, E-PA-07, 2-4.

APAC recommended a three-party share-the-savings rate to displace fuel for dual-fuel fired boilers. BPA would sell energy at the Displacement rate to a utility based on the displacement cost of alternate fuel used by industry. Then the utility would negotiate a share-the-savings rate with the industrial consumer. APAC suggested the use of No. 6 residual fuel oil as the basis for the displacement cost which would result in a NF-83 Displacement rate of approximately 7 mills/kWh. Engstrom, APAC, E-PA-07, 3-4; Opening Brief, APAC, B-PA-01, 94-95.

The WWPUD's recommend that the Displacement rate buy price equal the variable costs of operating a multi-fuel process steam facility. The determination of a unit variable cost would require the following information: the facility's variable O&M cost for nonelectric steam generation, the relative efficiency for the nonelectric and electric boiler, and the fuel price. The WWPUD's argue that this rate "is philosophically analogous to the displacement rates for thermal power plants." Hutchison, et al., WWPUD, E-WW-02R, 32-33.

BPA agrees with APAC and WWPUD's that loads with alternate fuel sources are important nonfirm energy markets. These loads can potentially increase BPA's regional nonfirm energy market to a significant extent thereby retaining the value of the energy in the Pacific Northwest. BPA also agrees that there is little difference in displacement of an alternate fuel and displacement of coal-fired generation. Displacement of alternate fuel loads results in conservation of nonrenewable fuel and mitigation of adverse environmental impacts. In response to APAC's seeking an explicit statement on the availability of the Displacement rate, BPA has stated in filed testimony and under cross-examination that the Displacement rate would be available for such loads. Metcalf, BPA, E-BPA-32, 57; Metcalf, BPA, TR 5814-5815.

Decision

BPA will offer nonfirm energy for the displacement of alternate fuel sources. The NF-83 Displacement rate is no longer a share-the-savings rate; it consists of two fixed rates for resource displacement. When Displacement rate energy is made available to end-user alternate loads, the rate will be the coal plant Displacement rate: 7.0 mills/kWh for nonguaranteed service and 8.8 mills/kWh for guaranteed delivery. BPA will apply this Displacement rate when the decremental cost of nonelectric steam production is less than the sum of the Standard or Spill rate (whichever is in effect) and 4.0 mills/kWh. (An extra 2 mills/kWh is included in this sale to allow for the retail utility mark-up.) Otherwise, nonfirm energy may be purchased at the Standard and Spill rates, whichever is in effect, when it is economic to do so.

BPA will apply the coal plant Displacement rate for two reasons. First, APAC contended that a share-the-savings rate would result in a Displacement rate of approximately 7 mills/kWh. Second, there is very little difference between coal plant displacement and fuel displacement for bi-fuel boilers. The precise terms and conditions for applying the Displacement rate to alternate fuel loads will be guided by the policy currently being developed for these loads.

11. Energy Broker Rate, EB-83

The EB-83 rate is applied to sales made pursuant to the Western Systems Coordinating Council (WSCC) energy broker agreement. There were no issues related to this rate schedule.

12. Reserve Power Rate, RP-83

The RP-83 rate is available for the purchase of power (1) to meet a utility's unexpected load growth; (2) to serve a purchaser's firm power requirements when there is no power sales contract in effect and BPA deems the RP-83 rate schedule to be appropriate; and (3) to serve a customer when BPA determines that no other rate schedule is appropriate. There were no issues related to this rate schedule.

E. Other Rate Design Issues

In this section issues related to the value of reserves analysis, BPA's General Rate Schedule Provisions, and the Hanford marketing rate are presented.

1. Value of Reserves Analysis

In the initial proposal BPA included a study assessing the value to BPA of the reserves provided by BPA's ability to restrict the DSI's load. Issues related to that study are discussed in this section.

Issue #1

Do the reserves provided by the DSI restriction have value during a surplus period?

Summary of Positions

The initial proposal assumed that without the DSI restriction rights, BPA would have installed combined cycle combustion turbines in FY 1982 to meet its reserve requirements. The cost associated with these turbines would be included in BPA's revenue requirement irrespective of the load/resource balance. BPA, E-BPA-7, Appendix A, A-5; Metcalf, BPA, TR 5400. The DSI's stated in their prefiled testimony that a surplus condition would not decrease the value of the reserves provided by the DSI restriction rights. Both the DSI's and BPA made long-term commitments, in the power sales contracts, affirming the availability of these restriction rights. The obligation to compensate these reserves is the same as if BPA had constructed actual generation facilities to provide reserves. Peseau, DSI, E-DS-10, 5-6. The OPUC and the PPC on the other hand believe the value that BPA has assigned the reserves provided by restriction of DSI load is overstated since BPA could use other means to provide reserves during a surplus situation.

The OPUC stated in prefiled testimony that neither plant delay nor forced outage reserves provided by the DSI restriction rights are necessary, since in the short run, the region is in a firm surplus situation. Therefore, the value of the forced outage and plant delay reserves approaches zero. Hellman, OPUC, E-OP-02E, 64-71. The PPC only examined the need for forced outage reserves provided by the DSI restriction rights. They concluded that significant evidence exists in the record indicating that the forced outage reserves will not be needed during the test period. Wolverton & O'Meara, PPC, E-PP-02, 25-30.

Evaluation of Positions

Plant Delay Reserves

In their testimony, the OPUC looked at the effect of delaying planned resources on the overall surplus/deficit conditions. They looked at the regional load and resource balance assuming the following plants were brought on-line as planned or experienced a delay from one to two years: Colstrip-3 and 4, Valmy-2, and WNP-1, 2, and 3. The results of their analysis show that even if every plant is delayed 2 years, the region is still in a surplus condition in five of the 8 years examined. Therefore, they conclude that plant delay reserves provided by the DSI restriction rights are unnecessary. This implies a zero value for these reserves. Hellman, OPUC, E-OP-02, 24-25; Hellman, OPUC, E-02-02E, 64, 67.

The OPUC analysis is inappropriate. First, the OPUC looks at the impact of delaying regional plants on the regional load/resource balance. However, the DSI's power sales contracts provide that BPA can restrict the DSI load, for plant delay purposes, to protect its firm obligations due to delay in Federal plants. Metcalf, BPA, E-BPA-32, 69. Second, BPA is unable to find any evidence that OPUC accounted for the water budget in their estimates of firm resource capabilities. Finally, BPA is unaware of any assumptions regarding firm surplus sales.

In valuing plant delay reserves, BPA used the Pacific Northwest System Analysis Model (SAM) to determine the probability of expected outages due to delay of Federal plant. SAM randomly models water conditions, loads, and thermal arrival and performance based on what actually occurred last year. The analysis incorporated the following assumptions:

(a) 1,000 megawatts of regional surplus is sold to the Pacific Southwest each year through the 7-year planning horizon.

(b) Due to fishery considerations, FELCC is reduced by 500 megawatts.

(c) Only Federal plants are considered in calculating the probability of second quartile restriction.

Contrary to the OPUC conclusion, SAM showed expected restriction of DSI load, due to plant delay, in the years 1987-1991. BPA, E-BPA-7, Appendix A, A-4-6.

Forced Outage Reserves

The OPUC and the PPC concluded that the forced outage reserves would not be used during the test period. Therefore, the costs associated with the combined cycle combustion turbine are not a reasonable approximation of the costs BPA would have incurred without the DSI restriction rights. The OPUC's LP model results indicate that the DSI capacity reserves are not necessary to replace any peaker-addition until 1984. Hellman, OPUC, E-OP-02, 25-26; Hellman, OPUC, E-OP-02E, 68-71. The PPC, in their testimony, agreed that the probability of restricting the DSI's for forced outage reserves is extremely low. Wolverton & O'Meara, PPC, E-PP-01, 29. However, under cross-examination, the PPC agreed that the reserves provided by the DSI's do have value to the BPA system. O'Meara, PPC, TR 6220. Nevertheless, they argued that the value of the reserves should be tied to actual chances of usage, rather than being levelized over a long period of time, especially in light of the DSI's professed uncertainty to remain in the region. Wolverton & O'Meara, PPC, E-PP-01, 29; Opening Brief, PPC, B-PP-01, 46-48.

Section 7(c)(3) of the Regional Act requires the Administrator to "adjust rates to take into account the value of power system reserves" made available through DSI restriction rights, as set forth in their power sales contracts. The current surplus does not make the value of the DSI restriction rights zero, because BPA's analysis treats the restriction rights as if they were generating reserves. Metcalf, BPA, E-BPA-32, 59. The PPC agreed under cross-examination that if BPA had acquired combustion turbines in place of acquiring restriction rights through new power sales contracts with the DSI's to provide system reserves, the fixed costs of those facilities would be included in the test period revenue requirement. O'Meara, PPC, TR 6257.

If an investor-owned utility had excess generating reserves during a period of surplus, it would be improper to exclude those reserves from rate base absent a finding that the reserves had been imprudently acquired or that the generating plants were not "used and useful." Madison Gas & Electric Co. v. Public Service Commission, 109 Wis. 2d 127, 325 N.W.2d 339 (1982). Hence, it would be improper for BPA to place no value on the reserves in the test period simply because of the surplus.

BPA agrees that no expected forced outages are likely to occur over the 7-year planning horizon, primarily because of the system surplus. BPA, E-BPA-7, Appendix A, A-8; Metcalf, BPA, E-BPA-32, 65-66. In valuing the reserves provided by the DSI restriction rights, BPA examined alternatives available to provide reserves in place of the DSI restriction rights. Without the DSI restriction rights, BPA assumed standby generation would have acquired to provide reserves. Metcalf, BPA, E-BPA-32, 59. Under cross-examination, the PPC agreed that the capital cost of standby generation would be properly included in BPA's revenue requirement and would not decrease because BPA was in a surplus condition, regardless of whether the unit was run. O'Meara, PPC, TR 6255-6258. However, to claim the combustion turbine is not used for forced outage reserves does not mean it is not needed for reserves over the 7-year planning horizon. BPA assumed the combustion turbine would be run to meet plant delay reserves. BPA, E-BPA-7, Appendix A, A-9; Metcalf, BPA, E-BPA-32, 67-68; O'Meara, PPC, TR 6259-6260. BPA's analysis correctly accounts for not utilizing the reserves for forced outage purposes by excluding any operating costs of the combustion turbines except for test purposes. Further, BPA incorporates reserves provided by DSI restriction rights in BPA's projections of long-term loads and resources. BPA, E-BPA-3, Attachment 2, 221-218. As such, these reserves are incorporated into BPA's long-term planning decisions. In prefiled testimony, the DSI's stated that under the new power sales contracts, both BPA and the DSI's established 20-year commitments affirming the need and availability of the DSI restriction rights. Peseau, DSI, E-DS-10, 6. The PPC agreed under cross-examination that as long as BPA provides service to the DSI's pursuant to their power sales contracts, BPA has the right to restrict DSI load for reserve purposes. O'Meara, PPC, TR 6261.

The PPC argues in their opening brief that the value of the reserves provided by the DSI restriction rights should reflect BPA's need for the reserves, not the DSI's ability to provide them. If the need for the reserves was reflected, the PPC asserts, the value of the reserves would be reduced. Opening Brief, PPC, B-PP-01, 41. The PPC states that the current need for the reserves is limited due to the available surplus. Since some of the surplus is sold in the nonfirm market to the Pacific Southwest, the PPC believe that this power can be available on a 60-day pullback to provide reserves. Wolverton & O'Meara, PPC, E-PP-01, 27; Opening Brief, PPC, B-PP-01, 41. Yet, as the DSI's, correctly noted in rebuttal testimony, a 60-day pullback provision on firm energy cannot serve as a substitute for reserves since, by definition, forced outages are unplanned. Peseau & Kavanaugh, DSI, E-DS-18R, 13.

In their opening brief, the PPC portrays BPA as ignoring the need for the reserves provided by the DSI restriction rights, in the value of reserve analysis, by citing the following two references from the record:

> BPA witness Metcalf admitted that the value of reserves calculation was not affected by the actual need for reserves." Metcalf, BPA, TR 5394. Mr. Metcalf further admitted that standby generation capacity was currently providing the portion of reserves DSI loads were unable to provide, and that standby generation could provide all needed reserves. Metcalf, BPA, TR 5395.

By lifting these two cites, the PPC ignored the content in which they were made and the qualifications which were added. The reserve calculation reference by the PPC was relating to the fact that the total cost of the combustion turbine is not used to value the reserves provided by the DSI restriction rights since this would overstate the value. BPA, E-BPA-7, Appendix A, A-8. The amount of reserves that the DSI's can provide is less than BPA reserve requirement, so the proration is based on the amount of reserves actually provided. Metcalf, BPA, TR 5394. BPA does consider the reserve requirement in the value of reserves analysis as to whether the facility assumed installed was sufficient to meet the reserve requirement. BPA, E-BPA-7, Appendix A, A-7. Further, if the DSI load have been greater then, the reserve requirement, the proration would be based on the level of reserves needed in the test period.

As to the second reference, the BPA witness was discussing the various options available to BPA for providing reserves. Under cross-examination BPA agreed that the reserve requirement could be meet by standby generation. However, BPA has chosen to provide reserves through the restriction rights to the DSI load. Metcalf, BPA, TR 5396.

Decision

The capital cost of the combustion turbine is the same as in the initial proposal, and remains unchanged by the existence of surplus on BPA's system. In the value of reserves analysis the surplus is reflected in BPA's projections of expected use of the DSI restriction rights.

Issue #2

Has BPA correctly valued the forced outage reserves provided by DSI restriction rights?

Summary of Positions

In the initial proposal, BPA assumed that absent the DSI restriction rights, 1880 megawatts of capacity would have been added to the system in 1983 through the construction of combined cycle combustion turbines. The annual investment cost for those combustion turbines simulates BPA's repayment obligation for those plants. However, the total annual investment cost would overstate the benefits derived from the DSI restriction rights. The cost to replace the DSI restriction rights is calculated by prorating the annual investment cost based on the amount of reserves the DSI's can provide in the test year to the amount of generation installed. BPA, E-BPA-7, Appendix A, A-7-8; Metcalf, BPA, E-BPA-32, 61. The PPC proposed that the annual investment cost should be levelized in real terms using the current rate of interest. Wolverton & O'Meara, PPC, E-PP-01, 32-33. The DSI's suggested that the capacity of the installed generation should be adjusted to reflect the fact that no generating facility is available with 100 percent certainty. Further the DSI's proposed that the level of forced outage reserves provided by the DSI's be measured at the generation level and reflect the maximum peak demand occurring during the test period. Peseau, DSI, E-DS-10, 10-15.

Evaluation of Positions

In prefiled testimony, the PPC proposed that the correct interest rate for investment cost is 10.57 percent based on a weighted average of the cost of funds assumed by BPA in OY 1984 (11.4 percent) and OY 1985 (10.3 percent). Wolverton & O'Meara, PPC, E-PP-01, 32. BPA used the interest rate in effect at the time the investment was made, since this simulates the obligations BPA would face if a generating unit had been acquired for reserves in lieu of the DSI restriction rights. The debt to be recovered is the debt incurred in 1983 at the interest rate during that time. Metcalf, BPA, E-BPA-32, 62. BPA assumed that the existing debt could not be refinanced even though the interest rates had declined. The DSI's agreed that to assume the debt could be repurchased is inappropriate since bondholders would not relinquish high interest bonds for lower interest with out demanding a premium payment. Peseau, DSI, E-DS-18R, 14. Under cross-examination the PPC agreed that assuming that refinancing was not available, the annual obligation would be based on the interest rate in effect at the time the debt was incurred. O'Meara, PPC, TR 6261-6262.

The PPC suggested that levelizing the investment cost in nominal terms is inappropriate as this results in the value associated with the reserves provided by the DSI restriction right being higher in real terms in the early years when the reserves are not needed and lower in the later years when the reserves will be needed. Levelizing the investment cost in real terms would eliminate this dilemma. Wolverton & O'Meara, PPC, E-PP-01, 34; Opening Brief, PPC, B-PP-01, 42. However, using a real carrying charge would not reflect BPA repayment and cash flow obligations and thus the actual demands placed on BPA's customers to recover the cost of the investment. Further, BPA's financial and legal structures would impede BPA's ability to use a repayment pattern that levelizes the cost of an investment in real terms over the life of the asset. Carr, BPA, TR 5414. The DSI's agreed with BPA's use of a nominal carrying charge. They further state that the DSI's would be overpaid only if the value assigned the reserves is greater then BPA's revenue requirement. Peseau, DSI, E-DS-18R, 15.

The DSI's objected to using the DSI load at the point of delivery to measure the capacity reserves provided. They reasoned that if BPA were to lose a generating plant equal in size to the second and third quartile demand, BPA would be able to support the outage through the generation available due to restricting the DSI load. Therefore, DSI demand providing forced outage reserves should be measured at the generation level. Peseau, DSI, E-DS-10, 10.

In the initial proposal, BPA used the DSI second and third quartile peak load in the month of January for prorating the annual investment cost of the combustion turbine. Metcalf, BPA, E-BPA-32, 65. BPA justified using January since the month of January represents the mid-point of the test period. Further, the DSI peak load in January is not significantly different from the DSI annual average peak load, and typically in long-term planning January is used as the base month for determining peaking values. Jones, BPA, TR 1935; Fuqua, BPA, TR 4188.

The DSI's proposed that the maximum expected peak demand represents the potential DSI restriction during the test period. The maximum expected peak demand occurs in June 1985, and they argue that this demand should be used in valuing the reserves provided by DSI restriction rights. Peseau, DSI, E-DS-10, 10-11; Opening Brief, DSI, B-DS-01, 47. The DSI's, in cross-examination, carried this argument to the extreme when they agreed that if the size of the second and third quartile was 100 megawatts for 11 months of the year and rose to 1,390 megawatts in the last month, the DSI restriction rights during the year would be 1,390 megawatts. Peseau, DSI, TR 6772. Using the last month of the test period to value the reserves would result in providing a value for a reserve level BPA would not be able to call on until the last month of the test period. Further, the level of reserves the DSI's could provide in June through restricting the second and third quartile is greater than the level of reserves BPA requires during the test year. The DSI's should not receive value for reserves provided above the amount BPA requires.

The PPC proposed that the size of the third quartile should be reduced by 222 megawatts to reflect restriction of the third quartile, under some water conditions, for return of provisional energy. If restricted for this reason, the PPC reasoned, the third quartile would be unavailable for restriction for forced outage reasons. The PPC suggests using the maximum amount of return energy, as identified in the Nonfirm Energy Program of 222 megawatts during the 40 water years of record. Wolverton & O'Meara, PPC, E-PP-02R, 34. Yet under cross-examination, the PPC admitted that the probability of third quartile restriction is quite small. Wolverton, PPC, TR 8505.

In BPA's Nonfirm Energy Program the return of provisional energy is modeled as a reduction in first quartile service. BPA, E-BPA-7, Attachment 1, 385. Because forecast reductions in first quartile service increases the DSI rate, a reduction in the value of reserves is not needed.

The DSI's also proposed adjusting the amount of installed capacity to reflect the fact that one megawatt of restriction right has more reserve support than 1 megawatt of a generating unit. Peseau, DSI, E-DS-10, 14. Opening Brief, DSI, E-DS-01, 47. BPA does not derate a generating unit to reflect forced outages; rather, forced outages are appropriately encompassed in BPA's reserve requirement. During the test period BPA would not require 100 percent of the capability of the combustion turbines to meet its reserve requirement. BPA, E-BPA-7, Appendix A, A-3. This and the fact that the installed unit consists of three plants, each of which has six turbines and one steam plant plus one plant with four turbines and one steam plant reduces the likelihood of a major impact due to forced outages to almost zero. Also, as pointed out by the PPC, the DSI restriction rights are not 100 percent reliable. Opening Brief, PPC, B-PP-01, 46-48.

Decision

In calculating the value of the forced outage reserves provided by the DSI restriction rights, BPA modified the initial proposal to reflect the DSI load at the generation level. Otherwise, the methodology remains unchanged from the initial proposal. The Value of Reserves Analysis is not an incremental cost analysis; rather, it attempts to show the actions that BPA could have taken shortly after passage of the Regional Act if the DSI restriction rights were unavailable. As such, the annual investment cost in FY 1985 is an embedded cost subject to BPA's financial and legal constraints. The value of the reserves provided by the DSI's reflects the amount of the forced outage reserve requirement the DSI's second and third quartiles can cover during the test period.

Issue #3

Has BPA correctly valued the stability reserves provided the DSI restriction rights?

Summary of Positions

BPA used the investment cost associated with a region-wide load-tripping scheme to value the stability reserves provided by the DSI restriction rights. BPA, E-BPA-7, Appendix A, A-9. The DSI's suggested that the investment cost of the load-tripping scheme proposed by BPA does not reflect all the costs faced by the region if the DSI restriction rights were unavailable. Regional customers would also face an additional cost due to the rotating interruptions. Peseau, DSI, E-DS-10, 17.

Evaluation of Positions

In prefiled testimony, the DSI's proposed a methodology to calculate the cost of an outage by developing a weighted average cost based on the cost of an outage to three customers classes: residential, commercial/irrigation, and industrial, and then applying this weighted average cost to the size of an interruption of the entire DSI load for 15 minutes. The DSI's proposed the total annual cost of an outage should be included in the value of the stability reserves. The cost of the alternative to the DSI restriction rights should reflect all the costs. Peseau, DSI, E-DS-10, 18; Opening Brief, DSI, B-DS-01, 48.

The PPC objected to adding the entire annual cost of an outage to the cost of providing stability reserves through a load tripping scheme. Wolverton & O'Meara, PPC, E-PP-02R, 17. Under the methodology proposed by the DSI's, the calculations assumed all regional customers would be exposed to unscheduled outages under the load tripping scheme proposed by BPA including the DSI's. Thus, the DSI's included the cost of an outage to the DSI's in their computation. Peseau, DSI, E-DS-10, 18. The PPC objected to adding the entire annual cost of an outage to the value of the stability reserve since this results in non-DSI customers paying for the outage costs they would face, but also paying for the outage costs the DSI's would face under the alternative load tripping scheme. Wolverton & O'Meara, PPC, E-PP-02R, 17; Opening Brief, PPC, B-PP-01, 3.

The PPC supports BPA's proposed methodology given the DSI's lack of support or documentation justifying the DSI's calculations. Opening Brief, PPC, B-PP-01, 39. As the DSI's stated under cross-examination their analysis based the size of the 15-minute interruption on a DSI total load of 2,900 megawatts which is not used anywhere in the case, but which represents an "approximate high utilization of" firm DSI load over a 7-year planning horizon. Peseau, DSI, TR 6768. Yet as the PPC noted, the 2,900 megawatts roughly corresponds to three quartiles of contract demand which bears no relation to the actual DSI load forecast during the test period. Opening Brief, PPC, B-PP-01, 37. The DSI further assumed that an interruption for 15 minutes every year was reasonable given that BPA might restrict the DSI load six times for an unspecified duration over the next 20 years for stability purposes. Peseau, DSI, TR 6769-6770. As the PPC observed the DSI's provided no evidence that six interruptions in 20 years is equivalent to a 15-minute interruption every year. Opening Brief, PPC, B-PP-01, 37.

This illustrates the problem of moving from the cost of an alternative reserve to valuing the function of a reserve. It is inevitable that restriction rights and alternative reserves will have differing effects. It could be similarly argued, for example, that combustion turbines are more flexible than the DSI restriction rights and the value of the additional flexibility should be subtracted from the value of reserves.

Decision

BPA retained the methodology used in the initial proposal. The DSI proposal moves from valuing an alternative to the DSI reserves to valuing the function of the reserves. Such a change would constitute a completely different methodology. Further, their proposal does not consider the cost of an outage to the region.

Issue #4

Has BPA correctly valued the plant delay reserves provided by BPA's ability to restrict the DSI's second quartile?

Summary of Positions

BPA used the SAM to determine the probability of DSI second quartile restriction during periods of plant delay to value second quartile restriction of DSI load. Contractually, the DSI second quartile can also be restricted for poor performance of existing facilities or delay of conservation resources. However, SAM currently does not model these second quartile restrictions and thus the value assigned to plant delay reserves only reflects restrictions due to delay in Federal plants. BPA, E-BPA-7, Appendix A, A-4-7; Metcalf, BPA, E-BPA-32, 68-69; McCoy, BPA, E-BPA-47R, 1. The DSI's stated that the inability to model second quartile restriction due to poor performance of existing facilities and delay of conservation resources does not justify assigning a zero value to these reserves. In their prefiled testimony, they proposed a methodology to calculate the value of the reserves provided by second quartile restrictions of the DSI load due to poor performance of existing facilities. Peseau, DSI, E-DS-10, 24.

Evaluation of Positions

In their prefiled testimony, the DSI's proposed to estimate the value of plant delay reserves associated with second quartile restrictions due to poor performance of existing facilities. The DSI's proposed using the plant performance data contained in SAM to derive the probability distribution of the annual level of a plant's reduced capability due to poor performance. They translated this to a total energy outage by multiplying the length of the outage by the reduced capability. Expected DSI second quartile restriction for poor plant performance was calculated by the DSI's by taking the amount of the reduced capability that cannot be covered by unsold surplus on the system times the probability of occurrence. Peseau, DSI, E-DS-10, 25-30.

The PPC agrees with BPA that the DSI's analysis greatly overestimates the exposure of the DSI's second quartile to restriction due to poor plant performance. McCoy, BPA, E-BPA-47R, 3; Opening Brief, PPC, B-PP-01, 39. As pointed out in BPA rebuttal testimony, the DSI's assumptions overestimated DSI exposure to restriction for poor performance of existing facilities. First, their assumptions overestimate the chances of a plant being out for an entire month. The DSI's analysis assumed that if a plant is forced out of service it remains down for the entire month. Typical time for forced outage in SAM is 54 hours, not 720 hours. McCoy, BPA, E-BPA-47R, 3. Second, their assumptions underestimate the amount of unsold surplus which could be used to cover the outage. In determining the amount of available surplus they used the 40 years of record. SAM weighs the 40 years of record by the 102 years of flows at the Dallas. McCoy, BPA, E-BPA-47R, 3. Under cross-examination, the DSI's agreed that using a weighted 40-year average would place more weight on good water years, increasing the amount of available water. Peseau, DSI, TR 6786-6788. And finally, the DSI's stated that their analysis did not take into account the ability of the hydro system to shift and shape FELCC, or the contractual provisions that require BPA to make reasonable attempts to purchase power and call for voluntary regional curtailments before restricting the DSI's second quartile due to unexpected poor performance. Peseau, DSI, TR 6766-6767. All of these would reduce the DSI's exposure to second quartile restrictions due to poor performance on an energy basis. SAM does model random plant performance and SAM makes every attempt to meet firm load including advancing energy, purchasing energy or using reserved uncommitted regional resources. Only after all alternative means to meet firm load are exhausted does SAM curtail firm load. Therefore, the firm load curtailment shown in SAM most assuredly would constitute an upper bound on DSI second quartile restrictions; however, not all firm curtailment shown in SAM would be subject to DSI second quartile restriction. McCoy, BPA, E-BPA-47R, 1-2. Nevertheless, BPA agrees that the value of DSI restriction rights due to poor performance is not zero in the test period. Metcalf, BPA, TR 5802-5803, 8748. The DSI's object to a zero value for poor performance simply because SAM does not yet model these interruptions. Opening Brief, DSI, B-DS-01, 49.

The problem BPA faces is not the lack of a tool to determine expected restriction of the DSI second quartile restriction; SAM is capable of modeling these restrictions. The problem is that "poor plant performance" as contained in the DSI contracts has not been sufficiently defined in modeling terms within the Region. McCoy, BPA, E-BPA-47R, 1. The DSI's made no attempt, on the record, to address the problem faced by BPA. Instead, they proposed an alternative methodology that greatly overestimates the value of the reserves provided by DSI restriction due to poor performance by existing facilities.

Decision

DSI second quartile restriction due to delay of Federal plants was valued using SAM in the value of reserves analysis. To value DSI second quartile restriction due to poor performance of existing facilities, the firm load curtailments shown in SAM are prorated based on the output of Federal thermal plants to the output of Regional thermal plants. A portion of the firm load curtailments shown in SAM would be due to poor performance of existing facilities, and would be subject to DSI restriction. Prorating the firm curtailment provides a better approximation of the firm load curtailments due to poor performance than the methodology proposed by the DSI's.

2. General Rate Schedule Provisions

In the past, BPA's wholesale power rates have included a reference to diversity with respect to coincidental and noncoincidental demand billing. In the initial proposal BPA noted that adjustments for diversity may not, in the past, have been made "in an equitable manner."

Issue #1

Should BPA adopt a diversity adjustment or otherwise change its GRSP language to reflect diversity?

Summary of the Positions

The purpose of a diversity charge was identified as being "to compensate BPA for lost revenue due to combining demands from multiple points of delivery for billing purposes." Stevens, BPA, E-BPA-31, 13. BPA noted in prefiled testimony that the manner in which diversity charges are currently applied may not be equitable and that the existing diversity charge is based on outdated information. Stevens, BPA, E-BPA-31, 13.

The WWPUD's expressed concern about BPA's adopting a diversity adjustment, because BPA has not "shown how much this charge would collect, how it would be applied, what its impact on utilities would be, or even how much money BPA is losing, if any, by not having such a charge." Hutchison, et al., WWPUD, E-WW-01, 42. Furthermore, the WWPUD's note that "[t]he complete absence of a proposal, facts and analysis precludes the imposition of a diversity charge at this time. If a problem exists, analysis will reveal it. If that problem calls for a remedy, a proposal can be made on the record. . ." Opening Brief, WWPUD, B-WW-01, 76.

Evaluation of Positions

The WWPUD's are correct in asserting that BPA has not demonstrated the amount of money that this charge would collect. Therefore, it would be inappropriate to adopt a diversity adjustment such as described in BPA's prefiled testimony. However, BPA's proposed rate schedules do state that a diversity charge "shall be applied in a uniform manner among purchasers." BPA, E-BPA-7, Appendix RC, 126. This statement makes it reasonable for BPA to state how the charge (if applicable) should be calculated if the appropriateness of a customer's present diversity charge were reassessed. The manner in which the charge should be calculated is dictated by BPA's criterion set forth in the prefiled testimony. That is, the charge should compensate BPA for revenue lost from combining demands for multiple points of delivery for billing purposes. Stevens, BPA, E-BPA-31, 13. Thus, the amount of revenue that BPA gains from application of the charge should equal the revenue lost from coincidental billing.

Decision

BPA has not adopted a diversity adjustment for this rate proposal. No changes relating to diversity will be made in present billing practices. However, in the General Rate Schedule Provisions BPA has specified how diversity will be taken into account in the future so that if a customer's present diversity charge were to be reevaluated at some time in the future, charges (if applicable) would be assessed "in a uniform manner." The "uniform manner" is the specification of a diversity factor which shall be multiplied by the coincidental demands of the coincidentally-billed points of delivery in order to arrive at the billing demand for those points of delivery. This factor shall be based on historical data and shall be no greater than:

$$\text{Diversity Factor} = 1 + \frac{\text{Noncoincidental Demand} - \text{Coincidental Demand}}{\text{Coincidental Demand}}$$

3. Hanford

In June 1983, the IOU contract for the purchase of Hanford Extension Energy expired and was replaced with a new contract. Because the Economic Regulatory Administration (ERA) previously approved BPA's marketing rate for the sale of Hanford energy and BPA is seeking approval of the proposed rate, the Hanford marketing rate was included in the initial proposal.

Issue #1

How should BPA set the marketing rate for Hanford energy purchased by the IOU's?

Summary of Positions

BPA proposed that the Hanford marketing rate be set in a manner consistent with the May 8, 1974, letter agreement between BPA and the five IOU's purchasing Hanford energy. Historically, this rate has been set by contract. BPA included this rate in the initial proposal and in the hearing process because the current rate is expiring and because BPA is seeking FERC confirmation and approval of the new rate. Stevens, BPA, E-BPA-34, 1-4.

There was no cross-examination, prefiled testimony from the parties, or rebuttal testimony introduced into the record relating to the Hanford marketing rate.

Evaluation of the Positions

There are no positions to evaluate.

Decision

BPA has adopted the Hanford marketing rate as proposed in E-BPA-34.

CHAPTER VII

TRANSMISSION RATE DESIGN STUDY

A. Introduction

The Transmission Rate Design Study (TRDS) presents the rates developed for wheeling transactions and discusses the factors affecting rate design. Legislation and contractual requirements are primary factors considered in the development of rates. The rates also have been designed in accordance with the proposed transmission policy. Additional factors considered are treatment of non-Federal costs and uses, cost studies (TDLRIC and COSA), equitable sharing of the benefits and risks of the Federal Columbia River Transmission System (FCRTS), efficient resource utilization, rate continuity, and ease of administration.

The proposed rates are expected to apply to transactions under existing contracts and to new transactions under new contracts. The Formula Power Transmission (FPT-83) and Integration of Resources (IR-83) rate schedules apply to firm wheeling transactions on BPA's network transmission segment. The FPT-83 rate is BPA's traditional wheeling formula, and it applies to existing agreements only. The IR-83 rate offers a relatively new wheeling service for utilities wishing to revoke their current FPT agreements and for all future firm wheeling transactions.

For this rate proposal, new rate schedules are being offered on the Northern and Eastern Interties that apply to wheeled power on these segments. The Southern Intertie (IS-83) and the Northern Intertie (IN-83) rate schedules are calculated by the same method used for the Energy Transmission (ET-2) rate in 1981. The ET-83 rate schedule, which in the past had an intertie component, will be limited to wheeling on intraregional FCRTS facilities which excludes the Interties. The Eastern Intertie (IE-83) rate schedule is calculated differently from IN-83 and IS-83 because historical load data on this segment is not available.

The new Use of Facilities (UFT-83) rate schedule extends its availability to network segment facilities in conformance with the new transmission policy. The TRDS also contains a description of each rate schedule and comparisons of the projected revenue from transmission customers under both current rates and proposed rates.

B. Losses

Issue #1

Should losses be treated as a rate matter?

Summary of Positions

In response to a question from PG&E, BPA stated under cross-examination that it is BPA's policy to exclude wheeling loss replacement provisions and methodologies from its rate schedules. Diffely, BPA, TR 5937.

PG&E argues in its testimony, however, that loss charges are a major cost to utilities. Loss charges should be equitably allocated between Federal and non-Federal power using the system, and they should be adjusted coincident with new transmission rate filings. Buckingham, PG&E, E-GA-1, 16. PG&E supports its position with the FERC's August 3, 1982 "Order Confirming and Approving Transmission Rates" in Docket No. E-9563-000 (20 FERC 61,142). PG&E alleges that BPA's failure to update or develop loss factors applicable to the IS-83 and ET-83 transmission rate schedules denies parties the right to test BPA's choice of loss factors. Buckingham, PG&E, E-GA-1, 16.

Evaluation of Positions

BPA recognizes that losses are an important cost to a wheeling utility. BPA agrees with PG&E that loss charges should be treated consistently for all power on the system, and that loss provisions should be determined using the most accurate methods and the most recent system loss data available. BPA does not agree that the treatment of losses is an issue appropriate to this rate proposal.

Data on average system losses are periodically revised. Once approved, such revisions are incorporated into the loss formulas for wheeling contracts. Each revised BPA system loss factor in recent years has shown a decrease in average losses which has been passed on to the benefit of wheeling utilities through contractual changes. In any event, changes in conditions that would justify a review of BPA system average losses are not necessarily coincident with transmission rate proposals.

The cited FERC order (20 FERC 61,142) states the following concerning losses.

> BPA specifies loss provisions in the individual customer contract portion of the rate schedules rather than in the rates themselves. While this practice in and of itself is not unreasonable, the Commission believes that when provisions for energy losses in the transmission system are included by contract, there should also be provisions in the contract to allow for changes in losses due to new transmission efficiencies. Except for its fixed rate contracts, BPA has recognized this and has adjusted the loss provisions of its contracts accordingly. However, such adjustments to the contracts as currently written do not necessarily permit the loss factors to be adjusted coincident with new transmission rate filings. The Commission believes that further development of BPA's accounting for losses should be made to allow for more rapid adjustments to transmission losses.

The Order neither requires nor recommends that loss factor adjustments be a part of the transmission rate proposal. Rather, it finds BPA's long-standing assertion that losses are a contract matter to be "not unreasonable." The FERC does suggest that transmission loss adjustments be incorporated more rapidly into BPA's contracts when the accounting of its loss factors is updated. The FERC does not suggest that parties have a "right" to test BPA's choice of loss factors through the rate hearings. Nor do any of the statutes governing BPA's ratesetting authority require that loss factors be developed and tested in a rate development process.

Decision

Losses will continue to be treated outside of the rate process. The calculation of losses and provisions for return of losses will be contract terms. For a statement of BPA's proposed policy regarding losses for transmission service within the Region, parties may wish to refer to BPA's proposed transmission policy, published in the FEDERAL REGISTER on May 22, 1983. This policy development process is an appropriate forum "to test BPA's choice of loss factors."

C. Revenue Stability

Issue #1

Does an energy billing factor in the IR-83 rate jeopardize revenue stability?

Summary of Positions

BPA's initial proposal states that equity among customers within a customer class is served if revenue responsibility corresponds to the relative degree of use made of the FCRTS. This is reflected in the rates by the choice of both demand and energy as IR-83 billing factors. Use of these billing factors tends to shift revenue responsibility toward those wheeling customers that make the heaviest sustained use of FCRTS facilities. BPA, E-BPA-9, 5.

The DSI's, however, assert that this preliminary proposal makes it very difficult to predict BPA revenues. They charge that BPA cannot project accurately the amount of energy that will be wheeled by individual utilities or by the utilities as a group. Therefore, since a portion of the wheeling charge is based on energy transmission, BPA's wheeling revenues are not predictable. Mayson, DSI, E-DSI-12, 2.

Evaluation of Positions

The DSI's suggest two ways of providing for revenue stability. First, BPA could base firm wheeling charges solely on demand. Funds collected from nonfirm or other unanticipated transfers could be used to decrease rates on a month-to-month basis. Second, if BPA must retain a wheeling rate that contains an energy and capacity component, BPA should develop such charges to contain an adjustable provision that would correct for transmission system usage different from that forecast. Mayson, DSI, E-DSI-12, 2-3.

BPA agrees with the DSI's that one cannot predict with absolute precision the amount of future energy transactions for firm wheeling. On the other hand, contract demand as a billing factor is also subject to change during a rate period, usually upon 3 months' written notice. Since the variation of firm energy loads during the last 4 historical years has been minimal, there is no guarantee that the exclusive use of contract demand as a billing determinant will provide a significantly greater amount of stability. Mayson, DSI, TR 7213-7214.

Nonfirm transactions are considerably less stable, BPA, E-BPA-5, Attachment 1, 263-266, and to the extent that certain incidental transactions would become a part of the IR-83 service, an additional amount of instability would be introduced. The DSI's suggestions could reduce revenue instability, but not without disadvantage. First, a 100 percent demand charge would not serve BPA's concern that revenue responsibility should correspond in part to the degree of use made of the FCRTS. BPA, E-BPA-9, 5. Second, if BPA applied an adjustable rate, customers would be at risk that their firm wheeling rates would change on a monthly basis. Mayson, DSI, E-DSI-12, 3. Revenue stability would be gained at the expense of rate stability. If these monthly rate changes were to affect customer wheeling patterns, the monthly rate fluctuations could become that much greater. Finally, adjustable rates would multiply the effort of billing and contract administration.

Decision

The concern for revenue stability must be weighed against the advantages to BPA and its customers of a predictable firm wheeling rate. Given (1) BPA's concern that some costs be a function of energy use; (2) the fact that customers have never strongly favored adjustable rates; (3) that the capacity-energy split is not expected to disturb revenue stability to a significant extent; and (4) that the implementation of adjustable rates would impose administrative burdens without assured benefits, BPA has implemented the energy billing factor as stated in the initial proposal.

D. Treatment of Federal and non-Federal Transmission Service

Issue #1

Is BPA's treatment of wholesale power and wheeling transmission costs inconsistent?

Summary of Positions

BPA states in its initial proposal that, because some customer classes and the services they receive require the use of only certain portions of BPA's transmission system, transmission facilities should be assigned to nine segments according to the functions they perform. Accordingly, in the initial proposal, a given class of service is allocated a portion of the total costs of the category of facilities used. This method of cost allocation achieves greater equity than would be possible using a method that did not segment transmission facilities. BPA, E-BPA-5, E-1.

The NWU's object to the inconsistency they perceive in the application of "unbundled" transmission costs for wheeling rates but not for power sales. The NWU's point out that Intertie wheeling rates are added incrementally to the network rate for non-Federal deliveries outside the Northwest. On the other hand, an undifferentiated rate, which includes assigned transmission costs, is derived for BPA's power sales, whether delivered over the network or the Intertie. The result, according to the NWU's, is that Northwest utilities purchasing BPA's nonfirm energy would be required to pay the Intertie component of these rates, even though the power they purchase would not make use of the Intertie segment. They suggest that BPA should price the transmission of wholesale power in the same manner that it treats non-Federal power. Schultz, NWU, E-NW-7, 10-11.

The California Public Utilities Commission would separate transmission charges entirely from wholesale power sales. They argue that this would provide a clearer accounting of costs, rates that are easier to understand and administer, and rates that would promote a more efficient use of resources. Mattson, CPUC, E-CP-1, 27.

Evaluation of Positions

BPA's rate designs for the transmission of Federal power and for non-Federal wheeling reflect the differing nature of the services. BPA's transmission system exists primarily to market Federal power. As such, the cost of transmission facilities is integrally tied to the cost of production. Priority Firm sales, for example, are assigned costs from the generation-integration, network, fringe, and two delivery segments. These facilities were built in part and are used to market Priority Firm power, and the costs assigned to them are part of the production costs for this service. In contrast, the service BPA provides to non-Federal power is to transport it across portions of the transmission system at specific points of interconnection. The service is a more limited one, and the benefits of the integrated power system are not all-inclusive. The distinction may be described in this way: power sales customers are purchasing energy produced by the BPA system, including the transmission system; wheeling customers are purchasing the use of the excess capacity of the transmission system.

BPA is authorized to charge uniform rates for the sale of electric power or for non-Federal transmission or both, so long as the costs of the transmission system are allocated equitably between Federal and non-Federal power. Federal Columbia River Transmission System Act, 16 U.S.C. § 838h. Rates must be set with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Federal Columbia River Transmission System Act, 16 U.S.C. § 838g. The NWU's charge that BPA is inconsistent in its treatment of transmission costs between wholesale power sales and wheeling. Schultz, NWU, E-NW-7, 10-11. BPA argues the reverse. BPA's rates are developed to be consistent with the services provided and with its legislative requirements.

In addition, both the CPUC and NWU's address ease of administration as a factor to consider in their respective proposals. Mattson, CPUC, E-CP-1, 27; Schultz, NWU, E-NWU-7, 11. The CPUC asserts that its proposal will be easier to administer than BPA's initial proposal. The NWU's, alluding principally to the NF-83 rate, admit that their proposal will be more difficult to administer, but not by much. Schultz, NWU, E-NW-7, 12. However, if the issue raised by the customers were to encompass rates on all segments of the transmission system, both proposals would be much more difficult to administer and to understand because of their added complexity.

Decision

The transmission services received by purchasers of wholesale power and by wheeling customers are different in nature. BPA's rates are developed to reflect these differing services and to conform to its legislative requirements. That BPA has adopted its proposed method consistently in four successive rate cases, reinforces the decision to make no change from the initial proposal.

E. FPT-83 Rate Level

Issue #1

Should the levels of FPT rate components be "constrained" so that total projected FPT revenues match the COSA revenue requirement for non-Federal power?

Summary of Positions

The method used in BPA's COSA to determine the equitable allocation of costs to non-Federal power using the FCRTS is different from the FPT methodology used to determine the cost of service. Since FPT contracts indicate a specific rate setting method to be used, such methods were used in the initial rate proposal both to determine the revenue requirement, and to design the rate (contract level rates). This is different from the approach taken by BPA in the 1981 transmission rate case, wherein FPT tariffs were scaled down such that total revenue would match the COSA revenue requirement (COSA level rates). The approach used in the initial proposal for FPT contracts reflects BPA's concern for the need to adhere to contract provisions and maintain fiscal integrity. BPA, E-BPA-9, 3.

The NWU's charge that the method adopted in BPA's initial proposal results in FPT rates that would recover $26.2 million more than the non-Federal class revenue requirement in the COSA. For the NWU's, the practical effect of this procedure would be to pressure customers to switch to the IR rate schedule, which would require switching to the IR service. They state that BPA should not attempt to escape from its FPT contracts through the ratemaking process, particularly when IR contracts may not be available by the effective date of the rate change, and also considering that certain FPT contracts may not be revocable. Wilson, NWU, E-NW-8, 1-8. PGP agrees with and adopts the NWU's testimony that BPA overestimates the FPT revenue requirement by approximately $26 million. Garman, et al., PGP, E-PG-1, 77.

Evaluation of Positions

BPA is required by the Transmission System Act and the Regional Act to "equitably allocate" the costs of the transmission system between Federal and non-Federal power. The mechanism that BPA uses to demonstrate an equitable allocation is the COSA. Historically, firm wheeling transactions principally have been under the FPT formula. The FPT formula has been the mechanism by which sufficient revenue was collected to assure an equitable recovery of non-Federal costs. In 1981 the IR rate was introduced as an interim alternative to the FPT rate schedule. It was a new concept, untested by BPA power schedulers, and it was offered on an interim basis, pending the completion of a new transmission policy. 1981, Administrator's Record of Decision, VIII-10. As an experimental concept, it was not expected to be the standard by which equity would be demonstrated. During the 1981 rate case, BPA expressed concern regarding the consistency of certain FPT contractual requirements with BPA's more recent legislative requirements. BPA, TRDS, 1981, Exhibit J, 4-5. However, because of the interim nature of the IR-1 and the absence of a new wheeling policy, it was necessary that the FPT rate meet the "test" for the equitable allocation of transmission costs. Diffely & Schaller, BPA, E-BPA-54R, 4. "Constraining" the FPT rates was decided to be both reasonable and permissible on the basis of the contract language. 1981, Administrator's Record of Decision, XIII-4.

Concurrent with this rate case, a new transmission policy is being introduced, which describes the IR rate as the concept which BPA will apply to firm wheeling transactions in the future. BPA, E-BPA-FR-07, 21; Diffely & Schaller, BPA, E-BPA-54R, 4. Customers are offered a choice to sign a new long-term General Transmission Agreement or to remain under their existing FPT arrangements. It is no longer necessary to adjust the FPT rate in a way which the contracts never envisioned. Diffely & Schaller, BPA, E-BPA-54R, 4.

The decision not to constrain FPT rates to the COSA requirement may give the appearance that BPA is attempting to "force customers to accept IR service." If all of BPA's customers remained under their FPT contracts, BPA would indeed recover collectively about $26 million more than if they would convert to IR as projected in BPA's rate proposal. Based on BPA's forecast of the economic choices to be made by its wheeling customers, however, most customers are assumed to convert to IR contracts. BPA, E-BPA-9, Table 8. Applying this assumption, BPA has developed its IR and FPT rates so as to assure that it collects no more than its projected revenue requirement. BPA, E-BPA-9, 29-30.

BPA's proposed transmission policy states that FPT contracts which include (a) major services in addition to those provided by the terms of IR principles; or (b) rates which are unable to be adjusted, will not be required to be revoked when a customer chooses to convert to IR service. Flynn, BPA, TR 5871-5872. This is not to say that BPA will prohibit such contracts from being revoked. The implication is only that the terms and conditions under which such contracts would be converted from the FPT formula need to be negotiated. Flynn, BPA, TR 5872. Finally, draft IR contracts have been offered to BPA's firm wheeling customers for comment with respect to BPA's transmission policy development. However, BPA does not expect to complete IR contract negotiations with all customers by the effective date of this rate proposal.

Decision

Conversion of existing FPT contracts to IR contracts cannot be accomplished by a simple billing change. The IR service is different from FPT, and contracts must be negotiated specifically in order to change operations. This negotiation is a necessary prerequisite to changing rate schedules for billing purposes. Some FPT contracts provide for major services that are not covered by the IR service. In some cases, an FPT charge was agreed upon in consideration of other contractual factors.

For these reasons, BPA cannot guarantee that all FPT contracts will be convertible to IR, nor can it guarantee that IR contracts will be available and acceptable to all its firm wheeling customers by November 1, 1983. While

BPA has the legal discretion to charge FPT customers the full "contract" rate and not "constrain" the rate to the COSA revenue requirement, it will not do so under present circumstances. The final proposal "constrains" FPT rate components so that they recover no more than the revenue required by that customer class in the COSA.

F. Firm Wheeling Intertie Rates

Issue #1

Does an energy only rate design for intertie rates preclude the possibility of certain types of intertie services?

Summary of Positions

For this rate proposal, BPA has not assumed any new long-term firm service on its intertie segments. BPA, E-BPA-9, 13. Energy rates are proposed for each of the intertie segments which are applicable to all wheeling transactions on these interties. The energy billing determinant allows intertie service to be compatible with a wide range of eventual policy decisions on intertie transmission services. Flynn, BPA, BPA-39, 5.

The NWU's assert that the IS-83 is an energy rate based on a relatively low load factor service. They state that the absence of a capacity-based rate makes impossible the proper pricing of high load factor service. They recommend that a capacity charge be developed, so that a cost-based rate will exist for intertie service. Wilson, NWU, E-NW-8, 8-12.

Evaluation of Positions

The FPT intertie charge for firm service on the Southern Intertie has not been eliminated in this rate proposal. BPA, E-BPA-9, 23. However, under current intertie contract practices, it is not being offered for new intertie transactions. BPA, E-BPA-9, 13. The FPT intertie rate will be applied only to the existing contracts which include it. BPA, E-BPA-9, 23.

An energy rate (IS-83) is being offered for all intertie wheeling. This permits the cost of intertie transmission to follow the quantity of energy transferred. BPA, E-BPA-9, 13. Such a rate does not frustrate the proper pricing of a "high load factor" arrangement compared to a demand billing factor, but it does change that pricing to make heavy use more expensive. Diffely, BPA, TR 5893-5895.

BPA's stance in this rate proposal simply conforms to its current intertie access policy. Amounts of power purchased by Southwest entities are scheduled by BPA as requested. Energy scheduled under the Exportable Agreement allocation provisions is scheduled before all other energy, except the WWP-SDGE firm wheeling contract which predates the Exportable Agreement. BPA has preserved the access of Exportable Agreement parties by refusing to grant any firm contracts that would supersede the transmission of exportable energy.

Increased use of the Southern Intertie and the continuing surplus condition in the Pacific Northwest have caused BPA to reassess its policy regarding intertie use. BPA, E-BPA-9, 12-19. BPA has announced through a public involvement process its intent to develop an intertie access policy, which will address intertie availability in the future. BPA, E-BPA-9, 5.

Decision

The rate schedules for the interties will contain energy-only billing factors as described in the proposal. BPA believes that energy billing does not "frustrate" the proper pricing of high load factor service, but it accurately reflects the principle that the heaviest users of facilities should make a greater contribution to the recovery of BPA's costs. Given the fact that the process for the development of a Southern Intertie access policy will not be completed for some time after these rates take effect, BPA has selected the energy billing factor as having the greatest potential flexibility for use under a wide variety of contract services.

G. IS-83 Rate Development

Issue #1

Is the IS-83 rate methodology incorrect?

Summary of Positions

The IS-83 rate methodology derives a unit cost per monthly coincident peak megawatt for the intertie segment by dividing total allocated intertie costs by the total estimated monthly coincident peak megawatts. The methodology develops the intertie rate by dividing this unit cost by the ratio of the estimated average energy to 12-CP megawatts for all wheeling transactions on that segment. Diffely & Schaller, BPA, E-BPA-38, 4.

The NWU's assert that BPA's development of the IS-83 rate purports to measure the contribution of non-Federal nonfirm service to total intertie peak load at the time of each monthly coincident peak. The NWU's believe this approach is incorrect, because the service is nonfirm, and as such, poses no peaking requirement on BPA transmission. According to them, BPA's calculation itself is even incorrect. BPA should price non-Federal nonfirm intertie service at the average cost per kilowatthour of all intertie service. Wilson, NWU, E-NW-8, 13-15.

The CPUC argues that marginal cost pricing is the proper approach to wheeling rate development. According to the CPUC, marginal cost pricing promotes resource efficiency in a regulated market by requiring that prices be based on the seller's marginal cost, not on the benefits received by the customer. Therefore, transmission rates should cover the variable operating cost for transmission service. Only when capacity costs are incurred because a long-term commitment and deferrable investments are made would the CPUC propose transmission rates which exceed short-term marginal cost. The costs which correspond to "marginal cost" for the IS-83 service are the O&M annual costs less deferrals and depreciation. Mattson, CPUC, E-CP-1, 4, 14, 27-28.

SCE alleges that BPA has developed a rate for the Southern Intertie which collects about 40 percent of the annual cost of the Southern Intertie facilities. For this IS-83 rate to be equitable, the annual cost should be shared equitably between Federal and non-Federal power using the Southern Intertie. However, the amount of non-Federal energy assumed by BPA in developing the IS-83 rate amounts to less than 20 percent of the total Federal and non-Federal energy transmitted in 1982. Lindsay, SCE, E-CE-2, 10.

Finally, PG&E's position on this issue is that the highest incidental wheeling rate which can be justified would be based on the assumption that firm and nonfirm customers pay equally on an energy basis. A 12-CP estimator for service over the intertie may be applied as an allocation factor to establish an upper limit to the cost responsibility for incidental wheeling transactions on the intertie. Buckingham, PG&E, E-GA-1, 17.

Evaluation of Positions

BPA's proposed IS-83 rate approximates the average cost of firm wheeling transactions on the Southern Intertie. Diffely & Schaller, BPA, E-BPA-54R, 2. This method is consistent in principle with the SCE position that the total annual costs of the Southern Intertie "should be shared equitably between Federal and non-Federal power." In rebuttal testimony, BPA demonstrates that 31 percent of the total intertie costs are recovered by IS-83 transactions, which represent 29 percent of the 12-CP intertie loads. Diffely & Schaller, BPA, E-BPA-54R, 3 and E-CE-3. In its opening brief, SCE questions this rebuttal testimony, suggesting that BPA's result depends on an invalid treatment of its "capacity payments" to PGE and WWP. Opening Brief, SCE, B-CE-1, 46. SCE's criticism is mistaken, however, because these payments represent neither a cost nor a load to BPA. They are essentially a revenue received by BPA and returned to the owner of the intertie entitlement.

SCE is correct in one respect, however. BPA's rebuttal ought to have removed from the IS-83 coincident peak allocator 198 megawatts, which represent the estimated 12-CP megawatts of these "capacity payments." Such an adjustment would show that 31 percent of intertie costs are recovered by 25 percent of the 12-CP intertie loads. BPA maintains that this cost recovery is acceptably close to proportion of use.

The NWU's allege that BPA's IS-83 rate "purports to measure the contribution of nonfirm wheeling to total Intertie peakload." Wilson, NWU, E-NW-8, 13. However, BPA "purports" to do nothing of the sort. Diffely & Schaller, BPA, E-BPA-38, 4. Nor do the NWU's propose that it should. Wilson, NWU, E-NW-8, 14. BPA's proposal is the preferred method to achieve a reliable approximation of the average cost of firm intertie wheeling.

An application of the method used on the network to develop the ET-83 rate is another method which would achieve BPA's purpose on the Southern Intertie. However, this method would be unacceptable on the Southern Intertie, because too few firm wheeling transactions exist on this segment. The addition or expiration of any single contract could greatly affect the rate level in either direction.

PP&L argues in its cross-examination of BPA witnesses that the IS-83 ratesetting method conceivably could achieve absurd results. Wood, PP&L, TR 5902-5904. If nonfirm wheeling transactions were equal on a 12-CP basis to total firm intertie use, goes the argument, then nonfirm wheeling would recover 100 percent of the costs of the intertie, using BPA's method. This criticism by PP&L does not address specifically BPA's method but BPA's rationale in general: that a proper assignment of costs be based on the average cost of firm wheeling. Obviously, if nonfirm wheeling were the dominant feature of intertie use, such a rationale would be open to question. However, IS-83 transactions are not the dominant feature on the Southern Intertie, and the conditions PP&L describes do not exist on the Southern Intertie. BPA, E-BPA-9, 43. BPA's rate setting method on the Southern Intertie is a valid method, whose results have been demonstrated to be equitable. Schaller & Diffely, BPA, E-BPA-54R, 2. BPA's calculation is not incorrect. It accomplishes what it is intended to accomplish.

The NWU's assert that the IS-83 rate should be based on "the average cost per kilowatthour of all intertie service," firm and nonfirm. Wilson, NWU, E-NW-8, 15. SCE recommends allocating costs based on energy and calculating the intertie wheeling rates "based on all projected kilowatthours transmitted." Lindsay, SCE, E-CE-2, 10. PG&E has two suggestions. First, it would develop a 12-CP allocator for nonfirm wheeling and divide by total wheeling energy. Second, it would set the rate so that firm and nonfirm wheeling customers would pay equally on an energy basis. Buckingham, PG&E, E-GA-1, 17. The CPUC suggests that equity is best served by an intertie rate based on short run marginal costs. Mattson, CPUC, E-CP-1, 27.

Some of these proposed methods are roughly compatible with one another; some of them are in conflict. Most of them are reasonable alternatives. If, for example, BPA allocated costs to nonfirm transactions, or if it allocated costs by average energy, BPA would be hard pressed to argue against some of the methods proposed. That the resulting rates would vary considerably from BPA's present proposal is theoretically unimportant, since, as PP&L asserts, there can be a substantial range of reasonably cost-based rates. Wood, PP&L, TR 7125, 7127.

However, BPA does not allocate costs to nonfirm transactions, Diffely & Schaller, BPA, E-BPA-54R, 2, nor does it allocate costs by average energy. Diffely & Schaller, BPA, E-BPA-54R, 1. Furthermore, the parties have failed to demonstrate that BPA's own method is not also a reasonable one. The NWU's attempt appears to be based on a misunderstanding of the method's purpose. SCE's demonstration that the results of the method are inequitable has been shown to be erroneous. PP&L's claim that the results of the method could be erroneous if the circumstances were right is correct, but irrelevant. The remaining parties rely on unsubstantiated statements of inequity.

Decision

BPA finds the methodology used in the initial proposal to calculate the IS-83 rate to be reasonable. The resulting rate is well within the range of cost-based and commercially defensible rates for Southern Intertie wheeling. The positions of the parties showed that various other defensible methodologies exist, but they did not demonstrate that the BPA method was either incorrect or inequitable.

H. IN-83 Rate Development

Issue #1

Is the IN-83 rate methodology and development incorrect?

Summary of Positions

The Northern Intertie consists of existing lines between Custer substation and the border, one of the two 500-kV lines between Custer and Monroe substations, two 230-kV lines between Boundary substation and the border, and the associated substation facilities. These lines were not distinguished from the network in the 1981 rate proposal. BPA, E-BPA-9, 12. BPA's identification of Northern Intertie facilities as an intertie segment is based on a clear pattern of commercial use as shown by the actual transactions between Canada and the BPA system. BPA's records of Scheduled Interchange Accounts show all transactions between systems. These records indicate that commercial use is predominantly for transfers from Canada to BPA and other United States utilities. Flynn & Gilman, BPA, E-BPA-52R, 2.

PG&E objects to the BPA position that the second Monroe-Custer line should be part of the Northern Intertie. It states that this line was built primarily to "serve increasing industrial and other loads in the Bellingham, Washington area." In addition, PG&E points out that BPA's planning guidelines and load flow data show that the increased capability to export power from BPA to Canada and to exchange power for coordination purposes were more important factors in the construction of the Northern Intertie facilities than the increased imports they made possible. Buckingham, PG&E, E-GA-01, 14-15. PG&E further alleges that under a trust agreement (No. 140-03-99109) BC Hydro provided funds and equipment for Boundary substation and a line north to the border. Costs for these facilities should not be included in the Intertie North transmission segment. Buckingham, PG&E, E-GA-02R, 8.

SCE argues that, regardless of the segmentation issue itself, BPA has improperly developed this rate. SCE states that their records showing their own 1982 Canadian energy purchases indicate that the proposed IN-83 rate is too high. It claims to have purchased 1,994,000 MWh from Canada in 1982. The same purchases under the IN-83 rate would generate over 80 percent of the annual revenue requirement of the Northern Intertie facilities. This estimate is felt to be unrealistic considering that it does not include any transactions between Canada and the other California utilities or the Northwest. SCE suggests that BPA recalculate the IN-83 rate based on all projected kilowatthours transmitted, including Federal energy. Lindsay, SCE, E-CE-2, 10.

In its reply brief, SCE introduces three more comments of significance. First, it suggests that Canadian imports and the Bellingham load should share the cost of the two Custer-Monroe 500-kV lines in proportion to their relative uses of those lines. SCE, R-CE-1, 41-42. Second, it asserts that every kilowatthour transferred to and from Canada for the coordination of the hydro system must directly serve load, unless it is wasted or stored. BPA should not let such transactions "ride free" on the Northern Intertie. SCE, R-CE-1, 42. Finally, SCE urges BPA to quantify all uses of the Northern Intertie rather than to dismiss Federal uses as "insignificant." That such transactions would have a 12-CP factor of zero demonstrates the inadequacy of the 12-CP method. SCE, R-CE-1, 42-43.

Evaluation of Positions

The facilities in the Northern Intertie are the only interconnections between the Pacific Northwest Region and Canada. Both Custer-Monroe 500-kV lines were built with the ability to serve two functions: local load support and international commercial transfers. A 1969 BPA budget justification document states that the dual purpose of this line was to serve increasing loads in the Bellingham, Washington area and to provide transmission capacity for exchange of large blocks of power with Canadian power systems. Buckingham, PG&E, E-GA-1, Attachment 7, 1. The document does not characterize the first-named purpose as being "primary" or the second-named as being an "ancillary benefit" as asserted by PG&E. Flynn & Gilman, BPA, E-BPA-52R, 2; Buckingham, PG&E, TR 7199. While the second line provides reliability to the existing Custer load, it was segmented to the Northern Intertie, because it also provides a substantial increase in reliable import capability from B.C. Hydro. Flynn & Gilman, BPA, E-BPA-54R, 2, Attachment 1; Flynn, BPA, TR 5941; Gilman & Flynn, BPA, TR 8014-8018. Based on the additional capability of the Northern Intertie provided by this second line, it was segmented to the Northern Intertie. Gilman & Flynn, TR 5940-5941.

Furthermore, although expected use as indicated by planning guidelines may be considered in the rate development process, BPA segments and allocates costs based on the function the facilities perform. BPA, E-BPA-5, E-1. This is reflected in the Northern Intertie by the radial nature of the facilities and by their commercial use. Flynn, BPA, TR 8024. PG&E testimony admits that the planning guidelines had been cited at least partially due to PG&E's lack of any better information on the use of the Custer-Monroe facilities. PG&E acknowledges the inferior nature of planning guidelines in comparison to assessments of actual use, as a cost allocation method. Buckingham, PG&E, TR 7206-7207. BPA's Interchange accounts show that scheduled transactions on the Northern Intertie are predominantly for transfers from Canada to BPA and other United States utilities. Flynn & Gilman, BPA, E-BPA-52R, 2; Flynn, BPA, TR 5939.

Finally, PG&E made a suggestion that BPA had included certain costs already paid by B. C. Hydro. Buckingham, PG&E, E-GA-2R, 8. Such costs are not included in BPA's initial proposal.

Both Federal and non-Federal power using the Northern Intertie are represented in the records of scheduled interchange. The Federal power transactions are of two major types: hydro system coordination (transfers for storage, return of storage, transfers in event of immediate spill) and other transactions (purchases, sales, mutual emergency back-up). Of these two types, coordination transfers make up the preponderance of Federal power scheduled to Canada. Canadian entities are not expected to be significant purchasers of BPA power in the rate period, due to local surpluses. This expectation reflects historical use during the recent past. Flynn, BPA, TR 5923.

The amount of Federal power delivered to Canada for coordination purposes is predominantly scheduled during off-peak hours, due to the nature of transfers for storage. In addition, the allocation of transmission costs to Federal power transactions for coordination purposes would be inappropriate. Federal transfers for coordination pursuant to the Canadian Treaty and operating agreements are assumed to be balanced in value by the coordination benefits received by Canada under such agreements. Transmission costs for this purpose are not applied to coordination power scheduled northward; nor are wheeling rates applied to power delivered southward from Canada for return of storage or other coordination purposes.

Finally, the SCE argument concerning excessive revenue recovery stems from its having included in its calculation energy purchased from Canada for SCE's obligation energy account. The SCE witness apparently was not aware of this type of transaction. Lindsay, SCE, TR 7149-7150. BPA scheduled 992,000 MWh of bilateral wheeling to SCE in 1982. The difference between this amount and the amount SCE claims it purchased seems to be obligation energy purchased in Canada and returned to BPA. Historically, BPA has not applied wheeling charges to the return of obligation energy, due to contractual interpretations. Obligation energy was not included in the initial IN-83 rate development for this reason.

Decision

The IN-83 rate methodology and development used in the proposal are adopted for the final rates.

The segmentation to the Northern Intertie is appropriate in view of the present flow of commercial transactions as shown in BPA's records of Scheduled Interchange. The Northern Intertie serves the same purpose as other intertie segments, which is to operate as a conduit for collected bulk amounts of power for transfer between regions.

The segmentation to the Northern Intertie of the second Custer-Monroe 500-kV line is appropriate. The second Custer-Monroe line is a critical facility in providing the capability needed to import power from B.C. Hydro. Both 500-kV lines serve the integrated purposes of supporting local load and exchanging power with B.C. Hydro. As the usage of the two Custer-Monroe lines for these purposes appears to be of equivalent weight, it is reasonable to segment one line to each function.

Other than the segmentation of the first-installed 500-kV line to the network, no amount of costs will be deducted from the Northern Intertie facilities attributable to Federal power uses. Federal uses are relatively small in quantity and do not contribute to peak hour loading. Costs of other BPA transmission segments are not allocated to storage or coordination uses, so this is consistent with other BPA rate developments. Obligation energy returned for the account of a California utility will not be assumed as part of the energy load to which the rate will be applied.

I. ET-83 Rate Development

Issue #1

How should the ET-83 rate be developed?

Summary of Positions

As in prior BPA rate proposals, the ET-83 rate approximates the average cost per kilowatthour for firm wheeling service. The method BPA uses to develop the ET-83 rate is similar to the development of the energy component of the IR-83 rate. The rate is obtained by dividing the COSA revenue requirement for the firm wheeling class, adjusted for excess nonfirm energy revenue, by the amount of energy that firm wheeling customers are estimated to wheel during the test period. BPA, E-BPA-9, 27.

SCE states that the ET revenue requirement is divided improperly by firm wheeling energy (30,111,766 MWh), rather than by total wheeling energy (32,618,644 MWh). More importantly, since the ET-83 rate is only for the transmission of nonfirm energy and uses the same facilities as firm transmission under the IR-83 rate, it should not exceed the energy portion of the IR-83. Lindsay, SCE, E-CE-2, 8-9.

PG&E notes that BPA's incidental rates for wheeling services on the network and intertie segments are somewhat higher than the average rate for firm service. PG&E argues that the result is a "serious intraclass equity deficiency." The nonfirm wheeling customer has no assurance of service, according to PG&E, nor are facilities built to provide service for his uses. It is "unfair" to charge more for service which is not assured than for service which is assured. The highest rate which PG&E could justify would be based on the assumption that firm and interruptible customers pay equally on an energy basis. Buckingham, PG&E, E-GA-1, 17.

Evaluation of Positions

Comments from the California parties disagree as to the appropriate pricing of ET-83 service. BPA's position is most closely in line with PG&E's assertion that firm and interruptible customers should be charged equally on an energy basis. Though transmission facilities are not constructed solely to provide nonfirm wheeling service, energy transmitted on an incidental basis makes use of those facilities on capacity which is available. Because of the energy billing factor, the nonfirm wheeler pays nothing, unless energy is accepted for delivery. BPA's proposal is supported by two recent FERC decisions, which state that it is entirely appropriate to assign both fixed and variable costs to interruptible service up to the fully allocable cost of firm transactions. 22 FERC 63,083; 21 FERC 61,070.

PG&E, however, objects to the BPA position that a reasonable ET-83 rate may be slightly higher per kilowatthour than the average per kWh rate for firm service. Buckingham, PG&E, E-GA-1, 17. The ET-83 rate is meant to provide a self-executing incentive for wheeling customers to enter into firm transmission contracts when the wheeling need would be long-term or sustained. The calculation itself results in a rate that is higher than the average firm rate because ET-83 generates excess revenue, which, when credited back to purchasers of firm service, reduces the revenue requirement for that service. BPA, E-BPA-9, 25, 26, 29, 44-45. The result of this calculation in terms of the variation in the ET rate from the average firm wheeling rate amounts to 0.03 mills/kWh. To characterize this difference as "a serious intraclass equity deficiency" is a "serious" overstatement.

However, an examination of PG&E's own ET-83 rate calculation, E-CE-2, Attachment 8, demonstrates that this aspect of the rate calculation is not the major concern. Both PG&E and SCE object that the ET-83 rate is not based on total IR-83 energy transactions, but only energy designated as "firm". Buckingham, PG&E, E-GA-1, Attachment, 8; Lindsay, SCE, E-CE-2, 8. BPA's position has been that the ET rate attempts to approximate the average cost for firm service. However, due to the characteristics of the new IR service, a transaction which would be a nonfirm transaction under the ET rate for an FPT customer becomes a firm transaction under the IR rate for an IR customer, BPA, E-BPA-9, 4-5, thereby losing its differentation as nonfirm wheeling.

Decision

BPA has adopted for the final rates the same ET-83 rate development as in the initial proposal, with one change. BPA has used total IR-83 energy transactions rather than firm only, as suggested by SCE. BPA intends that the ET-83 rate level be slightly higher than the IR firm rate in order to provide a natural incentive in favor of formal wheeling agreements for long-term or sustained uses. This is a prudent business objective. The former situation led to difficult disagreements between utilities, pressured by the fact that characterization of "firm" wheeling as "nonfirm" could result in revenue loss to BPA over time.

J. Allocation of Transmission System Costs

Issue #1

Is BPA's method of allocation of transmission system costs incorrect?

Summary of Positions

BPA applies the 12-CP cost allocation method in recognition of the joint role of capacity and energy in rate development. While use of the transmission system at the time of system annual peak is important in determining a customer's cost responsibility, the 12-CP method also recognizes the importance of the overall system load pattern, customer load factors, and the diversity among individual utilities' peak requirements as factors to be considered. Diffely & Schaller, BPA, E-BPA-54R, 1.

SCE's prefiled testimony states that BPA has chosen the 12-CP method to allocate transmission costs "in part" because the 12-CP method reflects the use of BPA's system to transmit energy throughout the year. SCE suggests that more comprehensive measurements can be provided by methods which reflect use of the system during additional hours of the year. They believe the most comprehensive measure would be a method that reflects usage of the system during all hours of the year. This would be accomplished if transmission costs were allocated on the basis of all kilowatthours of energy transmitted, including Federal energy. Lindsay, SCE, E-CE-2, 10.

Evaluation of Positions

If BPA's entire purpose in allocating transmission costs were to reflect the energy use of BPA's system throughout the year, BPA would find it difficult to quarrel with SCE's assertion that the most comprehensive measure would reflect usage during all hours of the year. However, as SCE notes in its prefiled testimony and then ignores while relating its argument, this is BPA's position only "in part." Lindsay, SCE, E-CE-2, 10. SCE's entire argument consists of the simple assertion that average energy is a more comprehensive measure of energy use than 12 coincidental peaks. SCE assumes but does not explain that transmission costs should be allocated on the basis of all kilowatthours of energy transmitted. Lindsay, SCE, E-CE-2, 10. Since BPA does not agree with this unsupported assumption, it cannot find SCE's argument to be compelling.

Since the publication of BPA's first Cost of Service Analysis in 1979, BPA has classified transmission costs entirely to capacity. This reflects BPA's position that transmission system construction is controlled by the timing and location of peakloads. BPA, COSA, 1979, 29-30; BPA, Exhibit A, 1981, 44-45, 84-87; BPA, E-BPA-5, G-5; and BPA, E-BPA-5, G-10, G-11. The 12-CP cost allocation method does recognize that the transmission system was constructed at least in part to move large amounts of off-peak energy from resource to load. BPA, Exhibit A, 1981, 88-89. BPA, E-BPA-5, G-4. By averaging the twelve monthly peaks, the 12-CP method acknowledges the benefits to the transmission system from the diversity of the customers' peak loads. BPA, E-BPA-5, G-11; Diffely & Schaller, BPA, E-BPA-54R, 1. A method which relies on a single monthly peak would not. BPA, Exhibit A, 1981, 89. The 12-CP method modifies the influence of annual peak on the allocation between customer classes and allows recognition of class load factor as a cost responsibility determinant.

Decision

BPA has adopted the 12-CP allocation method for the final rates, as it has been adopted in prior rate cases. The argument by SCE in favor of an energy allocation, or some method based more heavily on energy, is not persuasive. Such methods would fail to give adequate consideration to the importance of peak demands on costs incurred in transmission system investment.

K. Underrecovered Costs of the Transmission System

Issue #1

How should prior underrecoveries of transmission costs be recovered from present ratepayers?

(For a discussion of this issue, please refer to Issue #2 in Revenue Requirement Study, Appropriate Cost Recovery.)

L. "Lost Revenue" Rate

Issue #1

Should BPA develop a rate for firm transmission of non Federal power on the Southern Intertie which would be based on the expected losses of revenue to BPA due to loss of access to intertie capability being used for such non-Federal power?

Summary of Positions

BPA indicated in its Transmission Rate Design Study that it had completed studies evaluating the nonfirm revenue loss associated with the wheeling of non-Federal power over the Southern Intertie, and that BPA was considering incorporating those revenue losses into a rate for use of the Southern Intertie. BPA, E-BPA-9, 13. At the time, BPA estimated the revenue impact to be about 6 mills/kwh. BPA, E-BPA-9, 13-14.

In clarification and cross-examination, BPA described its intended application of the proposed rate. It would only be applied to firm wheeling transactions which could not be interrupted in order to market Federal power. Flynn, BPA, E-BPA-53R, 1.

BPA's concern in developing this alternative rate was that a rate which takes into consideration only the actual investment and operation costs of the intertie would leave wholesale power purchases to suffer the BPA revenue losses that would accompany such transactions by other entities. Anticipated revenue losses could be recovered through higher firm power rates. Wedlund, BPA, E-BPA-17, 10. To the extent such losses are not anticipated, they result in reduced ability to make timely payments to the Treasury and in higher firm power rates in the future. BPA proposed this alternative rate to alleviate these potential problems, and invited comments from the parties regarding potential implementation.

BPA received objections from Pacific Northwest generating public and private utilities, and from California parties. A summary of these objections follows. This rate proposal is not cost based. Garman & Schultz, NGU, E-NU-01, 4-5; Lindsey, SCE, E-CE-01, 10-11. This rate violates past agreements and the intent of the legislative history of P.L. 88-552. Garman & Schultz, NGU, E-NU-01, 3-4; Parmesano, LADWP, E-LA-01, 12-13. This rate would discourage the expansion of the existing intertie with BPA and encourage construction of a competing intertie. Parmesano, LADWP, E-LA-01, 12-13. The analysis used to support this rate if properly done should yield an opposite result. Garman & Schultz, NWU, E-NW-1, 6.

Evaluation of Positions

The positions of the parties are fairly clear, with the exceptions of some objections which were based on incorrect assumptions as to existing contract rights or implementation. BPA's statements in clarification and cross-examination refuted objections that the rate would be forced onto Exportable Energy Agreement transactions, or applied to nonfirm wheelers to the detriment of economy energy transfers. Flynn, BPA, E-BPA-53R, 2.

However, all parties with an interest in firm intertie wheeling objected to the rate concept in principle.

Decision

BPA is greatly concerned by the results of studies demonstrating potential revenue impact on wholesale power purchasers as a result of loss of use of the Southern Intertie by BPA for sales of Federal power. BPA will not include this rate in the final proposal because of the need for further study and because the imminent development of intertie access policy may reveal other solutions.

CHAPTER VIII

WHOLESALE POWER RATE ENVIRONMENTAL IMPACT STATEMENT

A. Introduction

The National Environmental Policy Act of 1969 requires that environmental impact analyses be performed prior to arriving at decisions on major Federal actions that significantly affect the environment. BPA has prepared an environmental impact statement (EIS) to analyze the potential environmental effects of the proposed 1983 wholesale power rate increase.

An EIS helps insure that environmental information is available to public officials and citizens before decisions are made and actions are taken. The underlying purpose of preparing an EIS is to help public officials make decisions that are based on an understanding of potential environmental consequences and to take actions that protect, restore, and enhance the quality of the environment.

A Draft EIS was prepared on BPA's wholesale power rate proposal and circulated to the public for review and comment. Notice of availability of the Draft EIS was published in the FEDERAL REGISTER and comments were accepted through July 5, 1983. A Final EIS was prepared based on the Draft EIS and comments received on the Draft EIS. Copies of the Final EIS have been distributed to interested public and additional copies are available upon request from the BPA Environmental Manager.

B. Decision

BPA has decided to submit to the Federal Energy Regulatory Commission (FERC) a proposal to adjust BPA's wholesale power rates in order to achieve total revenues of $5.0 billion for the rate period November 1, 1983, through June 30, 1985. This revenue level is approximately $400 million more than the revenue level in the initial proposal. The decisions made regarding the proposed wholesale power rates are incorporated into the wholesale power rate schedules. These decisions are based on a comprehensive review of BPA's Final Environmental Impact Statement (EIS) on the 1983 Initial Wholesale Power Rate Proposal, as well as all other materials appurtenant to the rate process. The proposed rates would permit BPA to collect sufficient revenue to meet its statutorily mandated repayment requirement. Pending FERC approval, the proposed rate adjustment is scheduled to be effective from November 1, 1983, through June 30, 1985.

C. Summary

1. Alternatives Considered and Environmental Impacts

A number of alternative revenue levels and rate designs were evaluated in the EIS. These alternatives were selected in a manner intended to insure consideration of the range of all reasonable alternatives.

2. Revenue Level Alternatives

The EIS examined five basic revenue alternatives: base rate, no action, the initial proposal, direct financing, and long run incremental cost (LRIC) pricing.

The base rate alternative assumes that BPA's rates remained unchanged subsequent to those which went into effect on December 20, 1974. With the rates remaining constant, revenue levels would increase only as loads increase. This alternative establishes what would have happened had BPA taken no rate actions to increase revenues subsequent to 1974. Under this alternative, the revenue shortfall would increase throughout the period of analysis to the year 2000. The base rate alternative significantly undercollects revenue and would consistently violate BPA's statutory requirement to collect revenue sufficient to meet present costs. It would also render BPA financially insolvent, and require development of a mechanism to recover from future ratepayers funds to meet this increasing shortfall.

The no action alternative recognizes historic rate increases and assumes that BPA would maintain its existing rate structure. The no action alternative would also result in serious revenue deficiencies, providing only 85 percent of the revenue requirement used to develop BPA's initial proposal. This revenue shortfall would have to be added to revenue required during subsequent rate periods to allow BPA to meet its long-term financial obligations. The no action alternative would violate BPA's statutory requirement to be self-financing, since the agency would be unable to fully cover all financial obligations.

Revenue derived under the proposed revenue level alternative would be sufficient to meet BPA's rate period revenue requirement as determined in BPA's initial proposal and would represent a 19 percent increase over the estimated revenue that would be collected under current rates during the rate period using the initial load forecast. This alternative allows BPA to meet all financial obligations and provides that customers receiving service during the rate period would pay the full costs incurred during the same period to provide that service.

Under the direct financing alternative, BPA would finance completion of Washington Public Power Supply System WNP-2 and maintain the construction schedule for completion of WNP-3 through revenue rather than bond sales. The direct financing alternative should provide sufficient revenue to meet BPA's rate period revenue requirement if the decision were made to finance completion of Supply System WNP-2 and -3. Provided load forecasts are accurate, this alternative would not create the problems of under or overcollecting revenue.

LRIC or marginal cost based rates would price wholesale power at the projected long run cost of acquiring new power resources in the Pacific Northwest. Rates based on the long run incremental costs developed in BPA's 1983 Time-Differentiated Long Run Incremental Cost Analysis, if applied to BPA's projected rate period's sales volume would produce revenue significantly in excess of BPA's repayment requirement for the rate period and all years for the foreseeable future.

The revenue level based on LRIC pricing appears to be inconsistent with the directive in the Bonneville Project Act that BPA rates be the lowest possible consistent with sound business principles. Potential questions also would be raised as to how excess revenue should be distributed or invested. In the long run, however, the LRIC alternative would reduce the construction and operation of major new generation resources and encourage the highest level of conservation of electricity.

Increases in the price of electricity discourage consumption. Correspondingly, the level of adverse physical environmental impact associated with the production and consumption of electricity can be expected to vary inversely with the price of electricity (i.e., revenue level). These changes in impact would be offset to some extent by changes in the use of alternative forms of energy such as wood, oil, and natural gas. Some alternative energy sources (e.g., solar or wind) may involve lower levels of environmental impact than those associated with conventional thermal generation; other alternatives (e.g., wood) may involve higher levels of impact.

In contrast to physical environmental impacts, the short-term socio-economic impacts would be expected to increase directly with the price of electricity (i.e., revenue level). The level of revenue produced by rates based on marginal cost, for example, could have adverse financial impacts in the short run on virtually all regional power consumers, particularly energy-intensive industry, irrigators, and low income residential consumers. BPA's initial rate proposal would have significantly less adverse financial effects in the short term than the LRIC proposal. EIS Chapter II(B)(3).

It is BPA's conclusion after reviewing all pertinent information that the proposed revenue increase is environmentally preferred because it will best promote the national environmental policy as expressed in Section 101 of the National Environmental Policy Act ". . . to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of Americans." 42 U.S.C. §4331(a). It recognizes both the need to minimize potential adverse impacts to the physical environment associated with increases in the use of electricity, as well as the need to take account of the socioeconomic consequences of increases in electricity rates. BPA believes that the socioeconomic effects of this increase are within reason and would not result in undue hardship for BPA's customers. BPA recognizes that, on the one hand, the impacts of this rate increase may include reduced growth in the demand for electricity, a lowered rate of new resource additions, and spurred development of alternative energy sources. On the other hand, these impacts also may include additional air pollution, associated with increased use of woodstoves, and a strain on the budgets of lower income groups. The revenue increase also will enable BPA to conform to its statutory guidelines for meeting repayment requirements and to ensure the prudent operation of the Federal Columbia River Power System.

3. Rate Design Alternatives

BPA considered the environmental effects of a number of potentially feasible rate design elements and rate alternatives in arriving at a decision regarding the design of specific rate schedules. Such alternatives included those applicable to classification and allocation of costs, rate adjustments, revenue stability measures, a special irrigation rate, and the structure of the Nonfirm Energy rate.

As proposed, BPA has decided to continue to classify costs between capacity and energy based on cost causation principles. This method reflects the cost causation of BPA's resource mix. The rates which result from this method properly signal the relative costs of providing energy and capacity, and encourage consumption in a manner consistent with efficient long run allocation of resources.

Alternative classification methods which were considered included use of a fixed/variable approach, a LRIC classification of exchange resource costs, and a LRIC classification of all costs. BPA has also evaluated additional environmental effects associated with these alternatives. Alternatives which result in proportionately more costs classified to capacity, such as the fixed/variable approach, would constitute a disincentive for consumers to conserve energy. In the long run, BPA would need to add baseload thermal generation at an earlier date, resulting in an increase to BPA's revenue requirement in future years, higher wholesale rates, and localized effects to air, land, and water due to construction and operation of the new baseload plants. On the other hand, alternatives which classify more costs to energy, such as the LRIC classification of exchange costs and the LRIC classification of all costs, would result in rates which have adverse financial impacts in the short run on energy intensive consumers. While this would encourage more energy conservation and delay the need for large thermal plants, these effects would be offset by other impacts. First, there would be less of an incentive for consumers to practice load management to hold down peak demands. BPA would eventually have to add combustion turbines at an earlier date, relative to the proposed alternative, to meet peak demands. Therefore, this would constitute a shift of long run impacts to the physical environment, such as noise and air pollution, from areas in which baseload thermal plants would have been located to locations in which combustion turbines are installed and operated. In addition, there would be a greater likelihood of socioeconomic impacts associated with cutbacks or shutdowns of energy intensive industries if more costs were classified to energy.

With respect to test year hydro capability, BPA has decided to assume that Federal hydro capability will be levelized over the critical period. This assumption increases BPA's capability for surplus firm power sales during the rate period, while assuring enough energy in later years of the critical period to support anticipated long term surplus firm power sales. Therefore, this action is expected to enhance BPA's revenue levels during the rate period and maximize the efficiency of the hydro system, without significant long term adverse socioeconomic or physical impacts to the environment.

Beginning with this rate period, BPA has decided to include May in the lower cost summer demand period to reflect the decreased probability of a load loss during that month because of fish enhancement activities. This shift will benefit irrigators because May is part of the irrigation season.

BPA has decided to modify the billing factors for computed requirements customers to enhance revenue stability. Changing the billing factors to reflect BPA's obligation to provide a given level of service to these customers will compensate BPA for incurred costs. As other customers would otherwise have been assessed any revenue underrecovery potentially caused by the computed requirements customers, this design feature will more fairly distribute costs.

BPA has decided to include a contract charge to recover a portion of the costs of conservation. Such a charge may act as a disincentive to utilities to participate in BPA's conservation programs. This could have negative physical environmental impacts on air and water quality associated with the added operation of generation facilities. However, BPA has concluded that a contract charge is a necessary mechanism for recovering costs which can not be equitably recovered through rates. The charge is relatively small, thereby, minimizing its negative impact.

BPA has decided to continue to credit the DSI's for the value of the reserves they provide for the Federal system. Having the DSI's provide reserves has positive physical environmental benefits, as measured by avoidance of air and water pollution associated with the construction and operation of generation facilities. There are also positive socioeconomic impacts associated with the avoidance of the costs of those generation facilities. The impact of the credit which lowers the DSI rate may be a higher level of industrial production. This may have positive employment benefits in the region and negative physical impacts relating to the impact of the increased production levels on air and water quality. BPA considered but rejected an alternative to allow a credit to the DSI's based on the full amount of the value of reserves rather than sharing the savings with BPA's other customers. This alternative would have further lowered the DSI rate and would have raised the other rates for firm power.

BPA has decided to charge the DSI's to enhance revenue stability. Although some plants might foresee operating levels which are too low to justify incurring the customer charge, BPA has concluded that the benefits of this charge to BPA's revenue stability and the stability of wholesale rate levels in future years outweigh the small probability impacts associated with shutdowns of less economic plants during the rate period.

To further enhance revenue stability from the DSI's, BPA has decided to include an opportunity for BPA and the DSI's to agree on a lower rate. This "incentive rate" would be offered in exchange for commitments from the DSI's to operate at a specified level. This option would benefit both parties. The DSI's would have lower power rates, and therefore, be able to increase production levels with positive employment benefits for the region. BPA would have higher and more stable revenue with positive socioeconomic benefits for the region.

BPA has included two new automatic adjustment clauses for the purpose of improving revenue stability: the Exchange Adjustment Clause and the Supply System Adjustment Clause. The automatic nature of these clauses will allow for increases or decreases in rates, and thus a closer tracking of costs, without the delay and expense of formal rate hearings. These clauses will have positive socioeconomic impacts on the region by assuring that the costs scheduled for recovery during the rate period will actually be recovered from the rate period. Failure to achieve this would mean that future ratepayers could be allocated any revenue underrecovery.

As provided for in the Regional Act, BPA has again decided to include a Special Industrial rate for Hanna Nickel Smelting Company. The rate includes two options. The base rate is equal to the proposed Priority Firm Power rate and includes a value of reserves credit. A special rate of 7 mills per kilowatthour is also included for offpeak hour consumption with a limitation of no more than 10 percent of their Contract Demand requested during the peak period. The special offpeak rate would remain in effect until Hanna requests a higher percentage of peak period Contract Demand. The offpeak rate may allow Hanna to resume operation and thereby have a positive employment benefit in the region. There are also negative physical impacts on air and water quality associated with the operation of the smelter as a result of this rate adjustment.

BPA considered and rejected a special irrigation rate. The proposed Priority Firm rate already includes changes which benefit irrigators. While the irrigators as a consumer class do exhibit characteristics which are favorable to the Federal system, the proposed rate already reflects their contribution to lower system costs.

BPA has decided to continue the current structure of the Nonfirm Energy rate. As an alternative, BPA considered eliminating the Spill rate in order to increase overall revenue and improve revenue stability. BPA rejected this alternative in favor of delaying the implementation of the Spill rate by using the Displacement rate until it appears that moving to the Spill rate will result in greater BPA revenue or more thermal displacement. This decision was determined only after a thorough evaluation of the "significant aspects of the probable environmental consequences." Trout Unlimited v. Morton, 509 F.2d. 1276 (Ninth Cir., 1974). BPA has set forth sufficient information not only to enable the Administrator to consider the environmental factos and to make a reasonable decision, but also to allow the public to evaluate the environmental consequences independently Westside Property Owners v. Schlesinger, 597 F.2d., 1214 (Ninth Cir., 1979). This decision will result in positive environmental impacts on air and water quality associated with increased displacement of thermal plants. The increased BPA revenue from added sales will have a positive socioeconomic benefit by reducing BPA's firm power rate levels.

4. Decision Factors

BPA based its decisions concerning level and design of the rates on legal requirements, rate design objectives, and a consideration of environmental impacts.

a. Legal Requirements

The Bonneville Project Act requires BPA to establish rates that will recover all costs associated with production, acquisition, and transmission of electric power and to recover the Federal investment in the Federal Columbia River Power System. This Act directs that rates be designed to ". . . encourage the widest diversified use of electric energy . . ." at the ". . . lowest possible rate . . . consistent with sound business principles." 16 U.S.C. §832. The Transmission System Act placed BPA on a self-financing basis, requiring it to pay all operating expenses with revenue collected from its rates. 16 U.S.C. §837.

The Pacific Northwest Electric Power Planning and Conservation Act reaffirms directives in previous statutes and expands BPA's responsibilities. The Act contains specific provisions regarding power sales, rates, and procedures for establishing rates. 16 U.S.C. §839.

b. Rate Design Objectives

In addition to meeting legal requirements, BPA rates are designed to (1) meet its revenue requirement while distributing the burden in an equitable manner among recipients of the service; (2) encourage conservation and minimize environmental impacts; and (3) encourage efficient use of resources by reflecting costs incurred and benefits received. Additionally, consideration is given to rate continuity, ease of administration, revenue stability, customer acceptability, and ease of understanding.

c. Environmental Impacts

BPA's analysis of the environmental impacts of the alternatives revealed that the 1983 proposed revenue level would reduce regional load requirements from that expected if rates were not increased. By the year 2000, decreases in electricity load growth would reduce the regional need for new generation resources by the equivalent capacity of 49 megawatts of conservation, 1,131 megawatts of large thermal, 11 megawatts of cogeneration and 416 megawatts of small hydro. Elimination of the new generation would avoid accompanying land use, solid waste, water, and air quality impacts associated with power production. These environmental benefits would be somewhat offset by adverse physical enviromental effects resulting from increases in use of alternative energy sources.

The short-term socioeconomic impacts of the proposed revenue level would impact certain types of consumers more than others. Low-income consumers would be more affected by an increase in electricity rates than other residential consumers. Although the operation of the DSI's has been significantly curtailed even under current rates, they are forecast to increase production considerably under the proposed revenue level as the national economy improves. Some energy intensive industrial consumers could hasten decisions to either improve plant efficiency or shut down operations. While total acres of irrigated agriculture are expected to increase, some individual farmers could be forced to go out of business. While creating short-term economic hardships for those employed in these areas, there may be certain benefits to the physical environment.

The proposed rate design would not cause environmental impacts significantly different than those experienced under BPA's current rate design.

5. Mitigation

Existing and proposed conservation programs offered by BPA could mitigate socioeconomic impacts of the proposed rate increase. In FY 1981, BPA started energy conservation programs targeted at primary customer groups, State and local governments and nonprofit consumers in the Northwest. These programs would help residential consumers decrease electricity used for space and water heating, improve the use and distribution efficiencies of irrigators, and would aid commercial and industrial consumers in conserving electricity used in industrial processes and water heating. Also, under the terms of the Regional Act, BPA is required, among other things, to provide for the development of plans to protect and enhance fish and wildlife resources. BPA's proposed increase includes the cost of implementing these requirements. However, implementation of specific plans, programs, and projects will be undertaken independently of the above decisions on wholesale power rates and will undergo separate decisionmaking processes. Therefore, no monitoring or enforcement programs are applicable for mitigation of the adverse impacts of the proposed action and none have been adopted.

D. Issues

Issue #1

Does use of the TDLRIC Analysis results in classification cause damage to some of BPA's end-use consumers, specifically to industrial customers of public utilities?

Summary of Positions

BPA uses the Northwest Energy Policy Project (NEPP) model to develop forecasts of non-DSI industrial loads in the region. Taves, BPA, E-BPA-08, IV-11, 12. BPA has also presented, in its Final Environmental Impact Statement, analysis of the impacts of various rate levels on industrial customers of public utilities. BPA, Final Environmental Impact Statement, II-19-20, IV-37-43.

APAC has argued that use of the TDLRIC Analysis results for classification discriminates against high load factor customers and results in damage to APAC members. Shanker, APAC, E-PA-01, 4, 18, 19-22; Opening Brief, APAC, B-PA-01, 18-24; Reply Brief, APAC, R-PA-01, 14, note 8. Further, APAC argues that BPA has "totally ignored" the effects of its rates on non-DSI high load factor consumers. Shanker, APAC, E-PA-01, 20. See also Garten, APAC, TR 3708-3710, 3713-3716, 3723-3728.

Evaluation of Positions

APAC argued in its reply brief that empirical evidence of damage caused by the TDLRIC was presented in its opening brief, and invited the Administrator to review the evidence. Reply Brief, APAC, R-PA-01, 14, note 8, referring to Opening Brief, APAC, B-PA-01, 18-24. APAC's industrial witnesses addressed six concerns, which will be discussed in turn.

(a) Power costs have dramatically increased. Opening Brief, APAC, B-PA-01, 19. This is not the result of the TDLRIC methodology, which is only used to classify some of the costs incurred to meet statutory obligations, including the Supply System, the residential exchange, and conservation programs. Thus the "dramatic increase" in industrial power costs is a result principally of BPA's legally mandated responsibilities, not of one particular methodology.

(b) Electricity costs are a significant component of overall manufacturing costs. Opening Brief, APAC, B-PA-01, 19. This component is the joint product of available technologies and the prices of all inputs, including BPA's rates. This component may change for a variety of reasons, and may rise because the cost of a different input has fallen. It is not established as a matter of BPA's policy that end-use industrial power costs should be reduced or minimized at the expense of other customers' rates. Such a policy might actually lead to the anomalous result that changes in an industry's power's share of total costs, which result from changes in labor productivity or the cost of other inputs, would lead to changes in BPA's rates. In the absence of data concerning the change in this component over time, it is not possible to conclude firmly that BPA's rates, or any methodologies used in setting those rates, have caused any change.

(c) Electricity costs have impaired the ability of APAC's members to compete in national and international markets. Opening Brief, APAC, B-PA-01, 20-21. These arguments rely only on the statements by various witnessses that inter-regional cost comparisons can and are made, in deciding where to locate productive activity. BPA cannot and does not dispute the overall reasonableness of the argument by industrial witnesses that regional cost comparisons are made. Wollenberg, APAC, E-PA-03, 6-7; Baker, APAC, E-PA-04, 7-8; Czepiel, APAC, E-PA-05, 2-3; Tucker, APAC, E-PA-06, 2-3. However, without specific data on individual plants both in the region and elsewhere, it is not possible to measure the effects of BPA's rates. BPA's attempts to discover even the geographic locations of APAC member plants in the region were not successful: APAC refused to respond fully to BPA's data request in this regard. Inter-regional comparisons by BPA are therefore impossible on a practical basis.

(d) The adverse impact on competition will affect BPA's loads and revenues. Opening Brief, APAC, B-PA-01, 21. BPA recognizes that electricity prices affect the quantities of electricity demanded. Hoffard, BPA, E-BPA-11, passim; Roberts, BPA, TR 3893; Hoffard, BPA, TR 3897, 3898. However, many other factors also affect the demand for electricity, including the demand for the product for which electricity is an input. It is insufficient merely to state that loads will fall if prices rise; it is more important to consider all factors determining loads, and how those factors are likely to change in both the short run and the long run. BPA performs load forecasts that attempt this analysis, and invites continuing critical review of those forecasts by its customers.

(e) BPA's rates and rate design have an impact on jobs and future investment in the region. Opening Brief, APAC, B-PA-01, 22. This argument uses as support the fact that no new pulp and paper plants are being constructed in the Northwest, whereas 19 plants are under construction elsewhere.

There are many possible reasons for this new activity, and no evidence was provided that precludes these other factors.

(f) Finally, APAC argues that BPA has ignored the impact of rate levels and rate design on APAC's members. Opening Brief, APAC, B-PA-01, 23-24. As noted above, BPA attempted unsuccessfully to discover the geographic locations of APAC member plants in the region, by filing a data request. This information would have allowed BPA to explore the role of power rates in the level of productive activity at these plants. It is therefore not possible to perform the requested analysis of the impact of BPA's rates on APAC member plants.

APAC and the DSI's have also argued that BPA's wholesale rate classification, based in part on the TDLRIC Analysis results, is not translated perfectly into similarly classified retail rates for industrial customers. Opening Brief, APAC, B-PA-01, Appendix B, 11-12; Opening Brief, DSI, B-DS-01, 31. APAC's argument that BPA's wholesale rate design characteristics are not passed down to retail customers undermines their argument that damage is thereby caused to those retail customers.

Decision

BPA is concerned about the impacts of its decisions on the financial health of electricity consumers in the region. BPA attempts in the EIS to identify significant adverse impacts and to assess their magnitudes. However, that effort is hampered by a lack of information, due to the refusal of APAC to comply with data requests. Without the requested information, it is not possible to identify APAC members' plants, and so it is not possible to assess impacts specifically for this group of end-use consumers. It is true that BPA's rates have increased dramatically in the recent past, but it is also true that these increases are the result of BPA's statutory responsibilities. Many factors other than the price of electricity also determine financial health. None of these arguments addresses specifically a direct connection between financial health and the classification of some of BPA's costs. That connection is only alleged. It would be unreasonable to meet APAC's concerns by altering one part of the wholesale rate making process so far removed from the retail rates faced by these industrial consumers, given the evidence on the record.

Issue #2

Is BPA's analysis of wholesale rate design impacts inadequate?

Summary of Positions

BPA believes that the Draft EIS included sufficient treatment of the impact of wholesale rate design on its customers, revenue stability and system load factor. APAC's line of questioning in clarifying and cross-examination appeared to imply that BPA did not adequately attempt to measure the effects of wholesale rate design on non-DSI high load factor customers. Garten, APAC, TR 3713-3724, 3729-3730, 3735-3737. APAC's prefiled testimony asserted that BPA's load forecasting models preclude any analyses of rate design effects on energy consumption. Shanker, APAC, E-PA-01, 20. APAC again argued in rebuttal testimony that BPA has not analyzed the effects of its rate design on "future load growth and current energy and demand consumption. Cook, APAC, E-PA-08R, 27. Cross-examination by APAC reflected concern that BPA did not sufficiently address effects of its cost classification and rate design on system load factor. Garten, APAC, TR 3712-3713, 3718-3719, 3731-3717.

Evaluation of Positions

BPA devoted entire sections of the EIS to impacts of its rate design and alternative rate designs on its customers and its ability to recover revenues in the Draft EIS. BPA, E-BPA-8, II-59 - II-117, IV-103 - IV-118. With respect to a more detailed analysis, as APAC is suggesting, accurate quantitative modeling of the effects of wholesale "energy intensive rates" on retail industrial customers is not possible. As BPA stated during clarification testimony, wholesale rate designs are passed through to retail customers under varying retail rate structures over which BPA has no control. Taves, BPA, TR 3712. Therefore, wholesale rate design effects are much more difficult to accurately quantify than effects of wholesale rate levels. BPA stated in cross-examination that a reduced system load factor does not necessarily result in a more expensive and less efficient generating system. Rather, it is more important to have "loads parallel the capability of our resources when those resources are operated in their most efficient fashion." Taves, BPA, TR 3735-3737.

BPA's analysis of the record concludes that the various parties have not demonstrated a relationship between BPA's rate design and system load factor or a relationship between BPA's rate design and its ability to recover revenue.

Decision

BPA conducted sufficient analysis of impacts of its wholesale rate design. A more detailed analysis of these impacts, particularly impacts to a segment of its priority firm customer group, would be both impractical and require unwarranted speculation.

While BPA is including additional analyses of the effect of classification alternatives on cost allocation among customer groups, the record does not support the appropriateness of additional analysis of wholesale rate design impacts on system load factor or revenue stability.

Issue #3

What are the effects of BPA rates on irrigated agriculture?

Summary of Positions

BPA believes that its wholesale rates have some level of impact on the viability of irrigated agriculture. The Washington State Farm Bureau stated that recent wholesale increases have continued to adversely affect the agriculture industry. Ahrenholtz, WSFB, E-WS-01, 5. They asserted that BPA has imposed a hardship on irrigators by setting "high rates on low-cost spring and summer energy." Ahrenholtz, WSFB, E-WS-01, 11. The Oregon Department of Agriculture stated that "electrical energy costs are a major determining factor in whether to irrigate or not to irrigate." Kunzman, ODA, E-OA-01, 4. They also stated that it does not take "much of a cutback in irrigation to cut out one employee on an irrigated farm. Cutting that one employee has a domino effect and cuts perhaps three employees out of the region's economy." Kunzman, ODA, E-OA-01, 6. Many farmers will go out of business unless costs decline or income sharply increases. Torvend, ODA, E-OA-01, 14. The Oregon Department of Agriculture quotes irrigation district representatives who "feel that present pricing policies are defeating the purpose which is associated with irrigating more acres, using more energy, and increasing revenue to BPA." ODA, E-OA-01, 15.

Evaluation of Positions

Various portions of oral and written testimony included data and comments that reflect numerous factors other than BPA's wholesale rates which have affected irrigators. The Washington State Farm Bureau alluded to the current recession in the agricultural sector. Ahrenholtz, WSFB, E-WS-01, 8. The Oregon State Department of Agriculture, while referring to BPA's wholesale Priority Firm rate increase of several hundred percent since 1974, pointed out that the farm gate price for agricultural products has increased only about 20 percent during the same time period. Kunzman, ODA, E-OA-01, 3-4. Neither of these two parties presented data reflecting cost increases for other farm inputs during recent years, although they did make reference to the current cost/price squeeze facing farmers. Kunzman, ODA, E-OA-01, 3; Ahrenholtz, E-WS-01, 1. In cross-examination, NIU admitted that increased product prices would help the "economic well-being of the irrigator." However, NIU did not agree that product price was necessarily more important than costs of production. Hittle, NIU, DP 116.

As the Draft Wholesale Rate EIS indicates, BPA does not serve irrigation loads directly. Rather, power is delivered to irrigators through retail utilities. BPA, E-BPA-8, II-38. The Washington State Farm Bureau prefiled testimony included the servicing of retail utilities among the factors determining irrigation costs. Ahrenholtz, WSFB, E-WS-01, 5. NIU pointed out the "disproportionately higher share" of WNP-4 and -5 costs of Northwest Irrigation Utilities. Hittle, NIU, E-NI-01, 9. In addition, the Washington State Farm Bureau provided data reflecting irrigation costs as a percent of total production costs for Washington in 1983. The irrigation share inclusive of power costs accounted for 1 percent to 22 percent of total production costs, depending on cropping patterns, how far farmers have to lift the water and the type of irrigation system. Ahrenholtz, WSFB, E-WS-01, 8.

Based on the above information from the record, the extent to which electricity costs affect irrigators is subject to several factors, including product prices, cropping patterns and irrigation technology. Furthermore, electricity cost impacts are only partially accounted for by BPA's wholesale rates, since retail utilities' rate designs and costs other than purchases from BPA directly affect power costs to irrigators.

With respect to wholesale pricing of spring and summer energy, BPA has modified its allocation of costs in a way which results in lower costs to irrigation customers than would result absent the changes. First, no energy costs have been assigned to May. This action results in lower summer (April-August) energy costs and, therefore, lower energy charges to irrigators during a major portion of the irrigation season. Second, BPA moved the month of May into the summer capacity period (May - November). Since capacity charges during the summer are lower relative to winter capacity charges, the capacity costs costs to irrigating utilities will be less than they would be with May in the winter period.

Decision

The parties have not presented sufficient evidence to conclude that BPA's wholesale rates impact the irrigation customers of its retail utilities, any more than other factors relating to retail utility revenue requirements and rate designs, commodity prices, and other costs facing irrigators. Potential impacts of BPA's wholesale rates will be at least partially mitigated by its modified treatment of summer energy and capacity costs in a manner that is beneficial to irrigators, to the extent that these modifications are reflected in the rate designs of servicing retail utilities.

CHAPTER IX

TRANSMISSION RATE ENVIRONMENTAL ASSESSMENT

A. Introduction

An Environmental Assessment (EA) addressing the 1983 transmission rate proposal has been prepared by BPA. In developing the EA, BPA considered the effect which the transmission rate proposal might have on the demand for power and on the construction of parallel transmission facilities.

The EA was circulated to other agencies and to BPA's customers for review on August 29, 1983. In addition, a letter announcing the availability of the environmental assessment was sent to those who have expressed interest in BPA's rates.

The analyses in this EA lead to the conclusion that BPA's proposed transmission rates will have no significant effect on the quality of the human environment either through their direct effect on the retail cost and consumption of electricity or through the effect they might have on construction of non-Federal transmission facilities.

B. Decision

BPA proposes to raise its rates to its wheeling customers effective November 1, 1983, to meet its repayment obligations under the Federal Columbia River Transmission System Act, the Bonneville Project Act, and the Regional Act. This increase was computed by considering a variety of revenue level alternatives and rate design alternatives which are described in greater detail in an environmental assessment (DOE/EA-0224) and in BPA's initial and final 1983 Transmission Rate Design Study. BPA, E-BPA-09; FS-BPA-09. The proposed revised rates are designed to assure both adequate and equitable recovery of the costs incurred in constructing, operating, and maintaining the Federal Columbia River Transmission System (FCRTS), other than the costs incurred to deliver Federally generated wholesale power. Present wheeling rates would fail to fully recover that portion of the costs of the FCRTS allocated to non-Federal users. The environmental assessment analyzes the proposed wheeling rates for both the main grid and interregional intertie facilities and their impact on the revenue needs of BPA's wheeling customers, potential effects on the demand for electricity, and the potential for providing utilities an incentive to construct transmission facilities as an alternative to purchasing wheeling services from BPA.

C. Summary

The wheeling rate increase would equal less than 5 percent of the total revenue received by BPA utility customers during calendar year 1982. Total 1982 revenue was viewed as a conservative estimate of 1985 revenue needs for BPA's wheeling customers; their actual revenue needs are expected to be somewhat higher, because of increases in power costs and operational expenses. Because of this small impact on the overall revenue needs of the utility customers, the proposed wheeling rate increase will not significantly affect the demand for electricty and, hence, the need for construction and operation of generation facilities which could impact the environment.

Another impact considered in the environmental assessment is a possible inducement to construct parallel or alternative transmission facilities. A study of this possibility showed that the levelized unit cost of constructing, operating and maintaining alternative transmission facilities is at least 87 percent greater than the cost of wheeling under the proposed IR-83 rate. Thus, there would be no financial incentive under the proposed rates for the utility customers to construct and operate alternative or parallel transmission facilities. There is no evidence that the proposed intertie rates will have any impact on the customers' continued use of the interties for wheeling non-Federal power, or create a need for alternatives to the present interties. Therefore, no environmental consequences will result.

D. Issues

Issue #1

Would the proposed transmission rates cause a reduction in the demand for power and, hence, a reduction in environmental impacts resulting from the construction, operation, and maintenance of generation facilities?

Summary of Positions

The analyses prepared by BPA indicate the proposed increase in charges for BPA transmission services would represent only a slight increase (generally not more than 3 percent) in the retail cost of power to consumers served by BPA wheeling customers. Taves, BPA, E-BPA-56, 9. BPA believes this level of increase would not significantly alter plant construction, operational, and maintenance activities. BPA is not aware of any opposition to this position by other parties.

Evaluation of Positions

In view of the magnitude of cost impact on BPA's wheeling customers, the limited number of utilities purchasing wheeling services, and the price elasticity of demand for electricity, it is reasonable to conclude the proposed rate increase will have no significant effect on the construction, operation and maintenance of generation facilities.

Decision

Implementation of the proposed transmission rate increase should not be precluded by any potential environmental effects associated with the construction, operation or maintenance of power generation facilities.

Issue #2

Would the proposed transmission rate increase result in the construction of redundant transmission capability?

Summary of Positions

BPA analyses indicate the proposed transmission rates offer BPA wheeling customers a lower cost option than constructing their own facilities for power transmission. Taves, BPA, E-BPA-56, 9-11. BPA is aware of no parties that have presented evidence to the contrary.

Evaluation of Position

BPA analyses, which considered a variety of construction circumstances and financial assumptions substantiate the conclusion that the proposed transmission rates would not provide BPA's wheeling customers with an incentive to build parallel transmission facilities.

Decision

BPA's transmission rate proposal requires no modification in order to avoid environmental impacts that could result from independent construction by BPA wheeling customers of parallel transmission facilities.

CHAPTER X

COMMENTS OF PARTICIPANTS AND EVALUATION

A. Introduction

This chapter addresses the comments of the public concerning BPA's 1983 proposed Wholesale Power and Transmission Rate adjustments. BPA procedures designate as participants either interested individuals or groups who wish to participate in the development of BPA's rate proposals without incurring the obligations placed on parties.

The participants' portion of the Official Record consists of the transcripts of 15 field hearings held from April 11 through April 21, and on July 20 and 21, 1983, at which 219 people made comments. BPA also received 2,091 letters and petitions, and 21 telephone calls by July 29, 1983, the close of the comment period. The names of the participants who commented on BPA's proposal are listed in Appendix C.

Based on review of this portion of the record, 17 topics have been identified for evaluation that reflect the general concerns expressed by the participants. Within each of these topics are one or more issues. Each issue is evaluated. However, because of their volume, individual comments have been consolidated into a general representation of positions on each issue. The comments have not been attributed to particular individuals. However, an indication of the frequency of the comments has been provided. Where more technical aspects of the issues have been addressed earlier in this Record of Decision, reference is made to the earlier discussion.

B. Need for Increase

Issue #1

Why does BPA need another rate increase?

Summary of Comments

One hundred and seventy-nine participants stated their opposition to any rate increase by BPA. In addition, 20 comments suggested that BPA should reduce its budget further, thereby reducing or eliminating the rate increase.

Evaluation of Comments

As a result of the Federal Columbia River Transmission System Act of 1974, BPA is self-financing. It receives no appropriations from Congress, as do most other Federal agencies, and must pay all operating expense with power sales revenues. The Bonneville Project Act requires BPA to set its rates to produce sufficient revenues to recover its operating costs and amortize, with interest, the Federal investment in the Federal Columbia River Power System.

The proposed rate increase covers a period from November 1, 1983, to June 30, 1985. Budget changes can be identified by comparing BPA's fiscal year (FY) 1983 (12 month period beginning October 1, 1983) budget with the funding levels associated with the initial proposal as revised in supplemental testimony for the operating year (OY) 1985, which is from July 1, 1984, to June 30, 1985.

BPA's costs of operation are increasing for several reasons, including inflation. As a result of the Regional Act, BPA is increasing activities in several program areas. The fish and wildlife and conservation programs increased by $55.2 million. Because of BPA's net-billing program, obligations to cover 100 percent of costs for Washington Public Power Supply System WNP-1 and -2, and 70 percent of WNP-3 are included. Costs for completing and operating WNP-2, as well as costs for placing WNP-3 into a minimum preservation state, are being funded through rates rather than through additional bond sales. These costs, along with the interest payments on the bonds already acquired for the three plants, require an increase of $213 million.

The residential exchange component of BPA's budget accounts for the largest cost increase. This component, mandated by the Regional Act, requires BPA to purchase a certain percentage of kilowatthours used by the residential customers of the exchanging utilities (predominantly investor-owned utilities) at the utilities' average system cost, and to sell the same amount back to those utilities at BPA's Priority Firm Power rate. This "certain percentage" is increasing as required by the Regional Act from the 70 percent in effect during most of the current rate period to 90 percent during OY 1985. The increase in cost amounted to $326.2 million in BPA's initial proposal.

All of these factors combined have necessitated a rate increase to recover sufficient revenue to meet BPA's costs as required by law.

Decision

BPA must implement this rate increase to meet fiscal and legal obligations. The proposed increase represents the minimum necessary to assure prudent, financial operation of BPA.

C. Defer Increase Until Economic Conditions Improve

Issue #1

Could BPA defer the rate increase until economic conditions in the Region improve?

Summary of Comments

Seventeen participants expressed concerns about the timing of BPA's rate increase. They said that the Pacific Northwest was still having economic problems and, if the proposed rates were implemented, the recovery would be stalled.

Evaluation of Comments

BPA is very cognizant of the impact of the rate increase on the public. Although BPA is a nonprofit organization, it is required by law, specifically the 1937 Bonneville Project Act, to recover enough revenue to meet operating costs and to amortize the Federal investment in the Federal Columbia River Power System, with interest. As demonstrated in the response to the previous issue, BPA's costs are increasing.

In the recent past, BPA rate increases have not kept pace with increasing costs. Consequently, BPA faces an unpaid interest expense that has accumulated from past years. During the late 1970's, BPA fell significantly short of the amount of the planned amortization payments to the U.S. Treasury. The problem stems from a variety of factors including bad water conditions that affected revenues and nonfirm energy sales, and rapidly escalating costs. BPA must meet its planned amortization in order to ensure its fiscal integrity.

Many reductions have been made in the budget for the rate period. Conservation projects have been postponed, partially as a result of the current power surplus in the Region. Investment in new, nonessential transmission facilities also has been reduced.

In the 1983 Wholesale Power Rate Draft Environmental Impact Statement, BPA identified many of the socioeconomic impacts that could result from the proposed rate increase. Although BPA currently must implement a rate increase, we are aware of the need to consider economic conditions and have made substantial attempts to reflect these considerations in both the level of the increase and the design of the rates.

Decision

BPA has made a conscientious effort to minimize the amount of its rate increase by reducing costs where possible. The current economic climate was given very careful consideration in developing the proposed rates. The rates are the lowest possible which would be consistent with sound business principles and enable BPA to meet its statutory obligations.

D. Supply System Plants

Issue #1

Should BPA be responsible for paying the costs of Washington Public Power Supply System WNP-1, -2, and 70 percent of -3?

Summary of Comments

Ninety-five participants mentioned their concern for BPA's payment of the costs of WNP-1, -2, and -3. Most of the responses mentioned their disappointment at not being a part of the decisionmaking process when plans were made to construct the plants.

Evaluation of Comments

BPA received authorization from Congress in the Public Works Appropriations Acts of 1970 and 1971 to contract with the Washington Public Power Supply System for the purchase of all electricity from WNP-1 and -2 and 70 percent of that from WNP-3. BPA entered into these contracts in the early 1970's during a period when future loads were projected to exceed existing resources. It was a decision made with the customers of BPA and the ratepayers of the Northwest in mind.

Payments are made to the Supply System through BPA's "net billing" process. Each participant served by BPA makes payments to the Supply System and receives an equal amount of credit from BPA on their power bill. The net billing continues until each participant has paid and received credit for its total annual share of Supply System costs. Further discussion of the Supply System costs is found in Chapter III, Funding of Supply System Costs.

Decision

BPA has a contractual obligation to begin funding Supply System WNP-1, -2, and 70 percent of WNP-3 by specified dates. These dates have past and BPA intends to fulfill the terms of its contracts with the Supply System and its customers.

Issue #2

Should the costs of plants currently under construction or mothballed, but not in operation, be included in BPA's rates?

Summary of Comments

Twelve participants expressed concern over the fact that their rates included the costs of resources not yet producing electricity.

Evaluation of Comments

Contracts entered into by BPA with the Supply System cover payment to the Supply System for the cost of power from WNP-1 and -2 and 70 percent of WNP-3. The agreement was that BPA would commence payment for this cost of power, equal to the payment of principal and interest for the outstanding bonds, starting on specified dates, even if the plants were still under construction. A variety of problems have caused power production to be delayed, but payment for the bonds cannot be postponed. In the case of WNP-1 and -3, construction has been temporarily suspended, but payments on the bonds must be continued. BPA is contractually obligated to make these payments. Because of BPA's self-financing status, revenues to cover all BPA expenses must be collected to meet its obligations, including those on the net-billed Supply System plants. For a more detailed discussion of the Supply System obligations see Chapter II, Funding of Supply System Costs.

Decision

See Decision, Issue #1 above.

E. DSI Rates

Issue #1

Why does the rate to the DSI's have to be increased again?

Summary of Comments

This issue received more comment than any other, with 1,885 participants indicating that they opposed any increase in the DSI power rate. Nearly 50 percent of these comments were copies of two different master memoranda, each signed by an employee of an aluminum company. Forty percent were letters, oral comments at field hearings, or telephone calls by aluminum workers. The remaining 10 percent were participants not employed by aluminum companies.

A categorization of those opposed to the DSI rate increase for various reasons follows (total responses):

a. unemployment in directly related jobs (1738);
b. unemployment in indirectly related jobs (327);
c. reduced tax base (150);
d. aluminum industry leaving the Region and discouraging new Regional industry (382);
e. harm to related businesses (102);
f. harm to other businesses (219);
g. damage to local and Regional economy (217);
h. damage to U.S. economy (27);
i. forced migration of unemployed (116);
j. psychological effects (13);
k. family disruption (45)
l. permanent unemployment (53);
m. inability of local aluminum to be competitive (5); and
n. possible "death spiral" (7).

Other comments include the following:

a. raise residential rates instead of industrial rates, so that people can continue working (21);

b. sell power at the spill rate presently applied to nonfirm sales to California (189);

c. let DSI's have a fair rate that does not subsidize other rate categories (95);

d. lower the present DSI rate (36);

e. higher rates disrupt individuals, families, and communities (133);

f. residential rates will have to be increased to cover lost load if DSI's close (129);

g. U.S. could end up purchasing foreign aluminum, thereby placing the country in a poor national security position (4); and

h. DSI's might close down, causing unemployment and an increase in those on welfare (203).

There were five participants who commented that the rates to the DSI's should be increased. Three participants criticized any move to lower the DSI rates. They said that residential users would then have to make up the differences in revenue to BPA.

Evaluation of Comments

The rates for all of BPA's customer classes, including the DSI's, are to a large extent determined by provisions of the Regional Act. According to the Regional Act, the DSI rates prior to July 1, 1985, must be set at a level sufficient to recover certain costs, which include a significant portion of the costs of the IOU and public utility small farm and residential exchange.

BPA is concerned about the socioeconomic impacts resulting from recent low levels of operation by the DSI's. However, the depressed aluminum market has been a major factor in decreased DSI operating levels. On the basis of recent forecast information presented during the rate case, increased aluminum demand will be a factor in enabling BPA's DSI aluminum customers to operate economically at higher levels of production.

However, BPA is continuing to consider measures within its statutory authority to aid the DSI's. The recent offer of nonfirm energy to DSI customers through October 31, 1983, has resulted in significantly increased production. In addition, BPA has evaluated an incentive rate structure proposed by the DSI's during the hearings process that could allow the DSI's to purchase power at a lower per-unit cost while increasing BPA's revenue stability and ability to recover its revenue requirement.

The rates to the DSI's for the post-1985 period are anticipated to be relatively stable, based on provisions of the Regional Act and BPA's expected costs during the post-1985 period. After the upcoming rate period, the DSI rate will relate to the rates paid by comparable individual customers of the region's public utilities. For further discussion of the rate structure of industrial rate see Chapter VI, Industrial Firm Power Rate.

Decision

The rate increase to the DSI's accurately reflects increase in the costs which, under the provisions of the Regional Act, are allocated to these customers. The design of the new IP-83 rate includes an incentive rate option which provides an incentive to the DSI's to increase their production levels while achieving an improvement in the stability of production levels and achieving an improvement in the stability of BPA's Industrial Firm power revenue. Both the level and design of the rate are appropriate.

F. Conservation

Issue #1

In the face of obstacles for both off-budget and U.S. Treasury borrowing, should BPA finance conservation program levels directly out of rates?

Summary of Comments

BPA's conservation acquisitions through the test period will be financed primarily through borrowing, whether from the Treasury or alternative means, with 5 percent of expenditures to be financed out of revenue.

The Northwest Power Planning Council has expressed its concern that, because of obstacles to both Treasury borrowing (from OMB) and off-budget (utility) financing, BPA will be unable to meet the goals of the 2-year action plan. Thus, BPA should consider financing conservation levels directly out of rates to assure consistency with the plan.

Evaluation of Comments

The concerns of the Council are important both in terms of meeting the goals of the 2-year action plan as well as BPA's long-term acquisition targets. However, there is nothing on the record that will support rate financing beyond the 5-percent level. Also, under the financing arrangement suggested by the Council the conservation contract charge could be so great as to assure a high level of utility nonparticipation in BPA's conservation programs. This potential could block the achievement of the goals of the Council's 2-year action plan as well as BPA's long-term acquisition targets.

Decision

BPA will finance 5 percent of the conservation program directly from rates. Other alternatives will be sought for meeting any goals of the 2-year action plan which may be compromised through limited borrowing authority.

Issue #2

Is the level of effort and funding of the BPA conservation program appropriate?

Summary of Comments

Thirty-nine participants said that BPA's level of funding is too great and that, as a result of the projected surplus for the next 10 years, BPA should cut back on its conservation work and reduce the rate increase accordingly. Twenty participants stated that BPA should devote more funding to conservation, particularly in the areas of consumer education.

Evaluation of Comments

BPA has been charged by the Regional Act to acquire conservation as the priority resource for the Region. Toward that task, BPA's conservation program levels reflect a balance between the need to acquire conservation at targeted levels over the next 20 years and the need to hold down costs and minimize rate impacts during the near-term surplus years. Factors that were considered in the development of program levels were: (1) changing load/resource balances and surplus firm power sales forecasts; (2) existing conservation program activity and customer experience; and (3) the Council's Plan. Analyses by BPA indicate that either acceleration or deceleration of conservation acquisition from the current proposed levels would increase the system costs to BPA over the long term. For more detailed discussion of BPA conservation financing see Chapter II, Conservation.

Decision

BPA has proposed funding levels for conservation which reflect consideration of the surplus as well as the future need for power. BPA analysis has demonstrated that proposed funding levels constitute a least cost approach to conservation acquisition. Therefore, BPA has maintained funding for conservation at the levels reflected in BPA's initial proposal.

G. Nonfirm Energy

Issue #1

How should BPA nonfirm energy be marketed and priced?

Summary of Comments

Twenty-nine participants expressed concern that surplus hydro power was being sold at cheap rates outside the region. Thirty-eight participants said that the price of nonfirm energy sold to the Southwest should be greater than the price in the Northwest. One hundred and eighty-five participants suggested that the nonfirm energy should be sold at the cheaper rates to the DSI's.

Evaluation of Comments

BPA plans generating resources sufficient to meet the forecast needs (firm loads) of its Pacific Northwest customers, assuming hydro conditions equal to the lowest water period of historical record for the Federal Columbia River Power System (FCRPS) (the hydroelectric power system of the Columbia River). If hydro conditions are better than this, more energy will be available to sell. The additional energy that is available under favorable water conditions is called nonfirm energy. Although nonfirm energy may be available at different times throughout the year, it is most plentiful in the spring and summer as a result of the increased streamflows that result from melting snowpack in the mountains and release of water to increase river flows for migrating fish. The FCRPS does not have the ability to store all of this water in reservoirs when it is most plentiful and BPA must generate energy or spill the water.

Utilities both inside and outside the Pacific Northwest can purchase nonfirm energy. Pub. L. No. 88-552 guarantees electric consumers in the Pacific Northwest first call on firm and nonfirm electric energy generated at Federal hydroelectric plants in the region. When Northwest utilities choose not to purchase this energy, it may be offered to customers outside the region. Therefore, nonfirm energy is offered first to Northwest utilities and then to utilities outside the Northwest at the same rate. BPA sales of nonfirm energy to California also are limited by Intertie transmission capacity.

Revenue from nonfirm energy sales has reduced substantially the cost of electricity for Pacific Northwest customers. BPA credits the revenue received from nonfirm energy sales to its firm power rates. The final firm power rates have been credited with approximately $186 million of nonfirm energy revenues.

BPA is striving to expand its market for nonfirm energy in the Northwest. BPA currently is selling surplus energy to the DSI's at the Nonfirm Energy Contract rate, which is substantially lower than the DSI firm power rate. This energy is being sold under a short-term agreement that will end October 31, 1983.

Decision

BPA's final proposed Nonfirm Energy Rate schedule, NF-83, contains rates that are applicable under varying operating and marketing conditions. The Standard rate is based on BPA's average cost of service and includes costs of such resources as the Washington Public Power Supply System plants and FCRPS hydroelectric projects. BPA will market nonfirm energy at the Standard rate in the Pacific Northwest and outside the Region unless market conditions dictate otherwise.

BPA also will market nonfirm energy, concurrently with the Standard rate, at the lower Displacement rate. This will allow coal and nuclear resources to be shut down at times when the higher Standard rate will not economically displace these resources. In addition, BPA can market nonfirm energy at the Spill rate, which is lower than the Standard rate, in order to widen the nonfirm energy market sufficiently to increase nonfirm revenue. The Displacement rate can be offered concurrently with the Spill rate to allow additional shutdown of coal and nuclear resources. However, the Standard and Spill rates will not be offered concurrently.

BPA has not yet determined if similar special sales to DSI's will be made after October 31. BPA also has offered nonfirm energy on a short-term basis to utilities for use by their interruptible irrigation and industrial loads. A policy is currently being developed to guide the sales of nonfirm energy to the industrial loads. For further discussion of surplus sales see Chapter II, Marketability of Surplus.

H. Special Rate Assistance

Issue #1

Should BPA design special rates that provide rate relief to certain customer groups?

Summary of Comments

Many different groups of power users suggested special rate assistance. The breakdown includes the following: (a) 17 persons said they were too poor to pay their electricity bill because of unemployment; (b) 52 elderly and retired participants said they were on fixed incomes and could not afford another rate increase; (c) 63 farmers and irrigators said they would like to see a special irrigation rate (evaluation of this group is included in the next issue); and (d) 10 persons said residential customers should have rate reductions at the expense of industrial customers.

Evaluation of Comments

BPA is very aware of concerns of people who are experiencing genuine economic hardship as a result of increases in the cost of electricity. However, BPA sells power only on a wholesale basis and has no direct control over retail rates charged to individuals. If BPA were to implement special group benefits, then the loss in revenue would have to be recovered from some other group(s). This would undoubtedly raise questions of equity.

BPA's rates to the DSI customers are higher than those charged to Priority Firm power customers, in part, because the industries are assigned a significant portion of the cost of the residential exchange authorized by the Regional Act. The goal of the exchange was to spread the benefits of BPA's hydroelectric resources to all residential and rural consumers in the region, including those served by investor-owned utilities.

Decision

Sections 7(d)(1) and (2) of the Regional Act authorize BPA to offer a discount to customers with low system densities or to direct service industrial customers using raw materials indigenous to the region. No other provisions for special rate relief have been expressed in the legislation relating to BPA's authority. Any additional rate relief would place an inequitable revenue burden on BPA customers not receiving such relief.

I. Irrigation

Issue #1

Should BPA design a special rate for irrigation farmers?

Summary of Comments

Ten comments were received from irrigators indicating that the proposed rate increase would have serious consequences on their livelihood. Sixty-four participants recommended that a special rate be applied to irrigators, since they are a seasonal off-peak load with primary consumption occurring during the high runoff portion of the year. Five participants at field hearings stated that they would consider accepting interruptible service by some method such as radio-controlled pumps, if it would give them a price break.

Evaluation of Comments

Electricity costs for irrigation pumping represent a significant variable cost to farmers. However, the design of both BPA's existing and proposed wholesale power rates provide substantial benefits to irrigators. Seasonal differentiation of BPA's demand and energy charges benefits summer loads. Furthermore, the initial proposal has extended the summer demand season to include May. Utilities with irrigation customers could also take advantage of BPA's existing rate design to reduce capacity charges by concentrating irrigation use in nighttime hours and on Sundays. Irrigators benefit also from the Low Density Discount.

For BPA to realize tangible system benefits from having interruption rights to irrigation load, a number of conditions would have to exist. These conditions would include (1) interruption rights with little or no notice, and (2) BPA control over load interruption facilities. These conditions would likely be viewed unfavorably by irrigators. For further discussion of special rate relief for irrigators see Chapter VI, Priority Firm power rate and Chapter VIII, Wholesale Power Rate Environmental Impact Statement.

Decision

BPA's rates already reflect the lower costs imposed on the Federal system by the predominantly summer loads of irrigators. Further, it has not been demonstrated that tangible system benefits will result from having interruption rights to irrigation loads. Rate relief to irrigators is not mandated by the Regional Act and may, in fact, conflict with the "sound business principles" objective of BPA ratemaking. There is no basis for implementing a special irrigation rate.

J. Tiered Rates

Issue #1

Should BPA provide tiered rates in order to benefit those who have implemented conservation measures?

Summary of Comments

Fifteen participants complained that, although they had been involved in conservation programs, their monthly power bills had still increased. They all felt that their rates should be reduced because of their conservation efforts, while other customers' rates should be increased to cover the difference.

Seven participants suggested that their rates should not be increased because they had been encouraged to buy all-electric houses and now their power bills are more than they can handle. They feel they are entitled to some type of tiered rate that would provide a base amount of power to them at a reduced rate.

Evaluation of Comments

BPA, as a power wholesaler, cannot apply tiered rates to retail residential users. Nevertheless, retail utilities may choose, as have several of BPA's customers, to apply tiered rates to their residential consumers. Even under uniform rates, however, consumers can benefit from cost-effective conservation measures by avoiding the need to pay for electricity that they have conserved.

Providing a low cost allocation of power to owners of all-electric homes would provide a distorted price signal to these users and would require other ratepayers to bear a cost responsibility disproportionate to their use of electricity.

Decision

Tiered rates will not be offered by BPA. However, customers that participate in BPA conservation programs may be eligible for special payment programs, such as delayed payment or reduced payment.

K. Demand Charge

Issue #1

Should BPA increase the demand component of its rate?

Summary of Comments

Four participants discussed the merits of reducing or eliminating any rate increase in the demand component of the rate structure on the grounds that the rate increase is primarily the result of BPA's payments to the Supply System, whose plants were planned primarily to supply energy. Three participants stated that demand charges should remain unchanged or be reduced, as directed by the Northwest Power Planning Council, and all cost increases should be included in energy charges.

Evaluation of Comments

BPA classifies its costs between demand and energy using methods based on the principle of cost causation. That is, classification of generation resource costs reflects the reasons that the various types of resoures were constructed. For example, thermal generation costs, including BPA's payments to the Supply System, are classified between demand and energy using the results of BPA's Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis. These costs are classified 83 percent to energy and 17 percent to capacity, because thermal plants are being constructed primarily to provide energy to the region. BPA classifies a portion of thermal resource costs to demand to reflect the capacity provided by thermal plants along with energy production. Any rate increase should contain a demand component to reflect the rising costs of BPA's generation resources and their contribution to demand requirements. An extensive discussion of cost classification is presented in Chapter II, Classification.

Decision

BPA is not changing its generation related cost classification methodologies for this rate case. The existing methodologies reflect that the Supply System costs are primarily energy related.

L. Public Participation

Issue #1

Does public participation really have an impact on BPA rates and rate setting procedures?

Summary of Comments

Three participants stated that BPA would probably not take any action on their comments.

Evaluation of Comments

BPA considers all comments and suggestions submitted by the public to be a very important part of its rate process. BPA makes a strong effort to encourage involvement of the public. These efforts include advertisement of public hearings and requests for letters; mailing hearing schedules to all participants and special interest groups; providing transcripts, exhibits and rate studies at the Portland Headquarters Reference Room, BPA's library in Seattle, and selected area offices for public review; and providing information to callers on toll-free telephone lines. All comments, whether oral or written, are delivered to responsible staff who are experts in specialized areas. The comments are carefully considered and analyzed before the final rate proposal is prepared. All letters are answered and all participants at field hearings receive special information in the mail. When adopting the final rate proposal, the Administrator must consider the entire record including all testimony at field hearings and formal hearings, and comments contained in letters from participants.

Decision

BPA will continue to develop and refine its public involvement program to ensure the public's understanding of rate issues, as well as of BPA's legal and financial constraints, in order to encourage the greatest amount of public participation possible. Although BPA cannot in all instances positively act on the recommendations of the public, BPA will continue to listen to the public's comments, study and evaluate those comments, and sincerely consider the evaluation when developing rates.

M. Fish and Wildlife

Issue #1

Should BPA's fish and wildlife program levels provide for (1) BPA funding of capital improvements for fish mitigation at certain U.S. Army Corps of Engineers (COE) hydroelectric projects; and (2) accelerated implementation of Yakima River Basin fish passage improvements?

Summary of Comments

BPA's direct case supports the proposed fish and wildlife program levels in the Revenue Requirement Study with projections of the costs of Columbia River Basin Fish and Wildlife Program measures BPA expects to fund in fiscal years (FY) 1984 and 1985. Palensky, BPA, E-BPA-20, 1-2. The fish and wildlife program levels in the final Revenue Requirement study are $22.1 million for FY 1984 and $25.1 million for FY 1985. The cost projections on which these program levels are based do not include the cost of a bypass system at John Day Dam, a vertical slot counter at The Dalles Dam, or temperature control devices at Detroit, Cougar, or Blue River Dams. Palensky, BPA, E-BPA-20, revised Attachment 2. These dams are part of the Federal Columbia River Power System (FCRPS) and are managed and operated by the COE. In the Revenue Requirement Study the amounts for repayment to the U.S. Treasury of the power share of the cost of capital improvements at FCRPS facilities are included under the heading "Future Federal Investment in Generating Projects" in Chapter 8. These amounts include payments to the U.S. Treasury for the cost of a vertical slot counter at The Dalles Dam, which the COE expects to become operational in March 1985. The repayment amounts do not include payments for any of the other improvements at COE dams, because the COE does not expect them to be chargeable to BPA in either FY 1984 or FY 1985. BPA's projections of the cost of anadromous fish passage improvements in the Yakima River Basin total $149,000 in FY 1984 and $1,194,000 in FY 1985. Palensky, BPA, E-BPA-20, revised Attachment 2, 6. In turn, these cost projections are predicated on the expected schedule for the implementation of Yakima River Basin passage improvements. Palensky, BPA, E-BPA-20, Attachment 7.

The Northwest Power Planning Council urges that BPA include in BPA's fish and wildlife program levels "sufficient revenues to provide full and timely funding of all measures in the Council's Columbia River Basin Fish and Wildlife Program which anticipate BPA funding, including those measures which call for BPA funding of activities at federal projects." The Council specifically requests that BPA provide for direct funding of the above-mentioned capital improvements at COE hydroelectric projects and that, in funding Yakima Basin passage improvements, BPA "adhere to the implementation schedule included in the rebuttal testimony of the Columbia River Inter-Tribal Fish Commission" (See CRITFC, E-CR-01R, Appendix 2). Council comments, 4-5. The Council asserts that not including the cost of the COE facility improvements and additional Yakima Basin improvements in BPA's fish and wildlife program levels is inconsistent with the requirements of the Regional Act and the provisions of the Council's Fish and Wildlife Program; that BPA's case fails to include explanations of why it is not practicable to fund these facilities; that the case fails to describe "allowances" available to permit funding these facilities; that the case fails to show commitments from other sources to fund the facilities obtained in consultation with Federal project operators and the Council; and that the case fails to show that BPA is unable to fund the facilities by reason of the requirements of section 4(h)(10)(A) of the Regional Act that BPA's expenditures for fish and wildlife shall not be in lieu of other expenditures authorized or required from other entities under other agreements or provisions of law. Council comments, 3-4. The Council recommends that BPA include in its fish and wildlife program levels funds for all Fish and Wildlife Program measures "which anticipate BPA funding," with the exception of measures for which there is assurance of funding from other sources in a form that has been made a part of the rate case record. Council comments, 5. The Council also states that it "does not consider any current absence of Congressional authority to constitute a barrier to implementation or BPA funding of program measures at federal projects." Council comment, 5.

Evaluation of Comments

With two exceptions, the section on fish and wildlife costs in Chapter III addresses the issues raised by the Council's comments. The discussion is not repeated here.

In asserting that BPA's case fails to address the issues in items 2-4 of page 4 of the Council's comments, the Council relies on provisions of the Columbia River Basin Fish and Wildlife Program. BPA's responsibility to fund the protection, mitigation, and enhancement of fish and wildlife stems from section 4(h)(10)(A) of the Regional Act, 16 U.S.C. §839b(h)(10)(A), not from the Fish and Wildlife Program. BPA's procedures to discharge this responsibility are the prerogative of Administrator, and are outside the authorized scope of the Fish and Wildlife Program. 16 U.S.C. §839b(h)(2).

The Council recommends that BPA include in its fish and wildlife program levels, funds for all Fish and Wildlife Program measures "which anticipate BPA funding," with the exception of measures for which there is assurance of funding from other sources in a form that has been made a part of the rate case record. If other funding became available, BPA would "reduce its spending plans accordingly or seek reimbursement for its expenditures." Council comments, 5. This ignores that rates would be established, and revenues collected, based on the higher program levels. BPA's rates must be based on costs and expenses BPA expects to incur. 16 U.S.C. §839e(a)(1).

Decision

BPA's fish and wildlife program levels will not provide for direct BPA funding of capital improvements for fish mitigation at the John Day, The Dalles, Detroit, Cougar, or Blue River dams. Direct BPA funding of the capital improvements at John Day and The Dalles dams would duplicate funding already appropriated by Congress to the COE. The COE, which also owns and operates the Detroit, Cougar, and Blue River dams expects to initiate construction of temperature control devices at these dams after FY 1985, if at all. The COE intends to seek appropriations for these improvements. The appropriate means for BPA to contribute to their costs is through normal FCRPS repayment mechanisms.

BPA's fish and wildlife program levels are sufficient to cover the cost of Yakima River Basin fish passage improvements which BPA expects to fund in FY 1984 and FY 1985. The proposed fish and wildlife program levels are supported by cost projections based on reasonable expectations regarding the schedule for Yakima River fish passage improvement implementation and expectations as to which of the improvements will be funded from other sources.

Issue #2

Should fish and wildlife activities be funded by BPA?

Summary of Comments

There were four participants who were opposed to BPA funding of fish and wildlife activities. They felt that there were plenty of other agencies in the state and Federal governments that were already responsible for fish and wildlife activities.

Evaluation of Comments

As a result of the substantial damage to fish and wildlife resources from the development and operation of Federal Columbia River Power System facilities, BPA has been required by the Regional Act (sections 4(h)(8)-(11)) to commit a portion of its revenue to the restoration and enhancement of fish and wildlife resources. A plan for the protection, mitigation, and enhancement, of fish and wildlife has been developed by the Northwest Power Planning Council. Since BPA is self-financing and all costs must be covered by revenues, any increase in BPA's fish and wildlife budgets must be covered by BPA's rates.

Decision

BPA must budget for its fish and wildlife expenditures, and the expenditures will be covered by BPA revenues, as provided by law.

Issue #3

Should preference customers pay for the entire Fish and Wildlife Program?

Summary of Comments

One participant complained that BPA's preference customers are singled out for funding the Regional Council's Fish and Wildlife Program. He said that, since all customers use hydro power, all customers should be paying for the Fish and Wildlife Program.

Evaluation of Comments

The hydroelectric resources of the FCRPS are part of the Federal base system (FBS). The FBS resources are used to service the Priority Firm power and firm capacity classes of service. The Priority Firm power class includes public bodies, cooperatives, Federal agencies and the residential and small farm load of exchanging utilities (primarily investor-owned utilities). Since the hydroelectric resources of the FCRPS are responsible for the damage that the fish and wildlife program is intended to mitigate, it is appropriate for the costs of the program to be recovered from the classes of service supplied by the FBS resources. For further discussion see Chapter II, Allocation of Fish and Wildlife Costs.

Decision

Test period fish and wildlife expenditures mitigate the effects of hydroelectric facilities on the Columbia River and its tributaries on the Region's fish and wildlife. Since these expenditures are mitigating the impacts of the hydro system on Columbia River fisheries, it is equitable to allocate such costs in the test period to firm power purchasers that are allocated costs of Federal base system resources.

N. Value of Reserves

Issue #1

Should the DSI's receive a "value of reserves" credit despite the existence of a substantial power surplus?

Summary of Comments

One participant has stated that, in the current situation where there is a projected surplus, the value of reserves credit does not make sense. The ratepayers have to pick up the $40 million credit for a cutoff contingency to the DSI's that most likely will not be used.

Evaluation of Comments

The DSI loads can be interrupted to protect the system from unforeseen conditions, and thus ensure the reliability of service to other customers. Since BPA can interrupt the DSI load, the region's ratepayers avoid paying for additional resources that would sit idle until an emergency occurred. This allows BPA to keep the cost lower to all customers than if resource generation had been added. In recognition of this service provided by the DSI's, BPA grants a credit to their rates. This credit is based on a "share-the-savings" method. This method recognizes the value of the reserves provided by the DSI's and risk of an outage or interruption of power to the DSI's.

New long-term contracts, signed in August 1981, between BPA and the DSI's affirmed the need for, and availability of, the reserves provided by DSI restriction rights. The Regional Act directs the Administrator to adjust DSI rates to take into account the value of reserves provided by those restriction rights. BPA considers the restriction rights as insurance or protection against forced outages, delays in construction of new plants, or system stability problems. As with any insurance, the protection is provided on a continuing basis and the costs should be paid accordingly.

In the past, had the restriction right not been available, BPA would have acquired generating resources to provide reserves. The capital costs of the resources would be included in BPA's revenue requirement even if the reserves were not used. The capital costs would not decrease if BPA were in a surplus situation. The operating costs would be eliminated or decreased, however, if the resources were not used or were used on a limited basis. BPA considers that the obligation to pay for reserves provided by the DSI's is the same as if generating facilities had been constructed to provide the reserves. In valuing the reserves, BPA has considered the reduced plant operating costs that would occur because of the surplus. For further discussion of the value of reserves credit see Chapter VI, Value of Reserves Credit.

Decision

BPA will continue to provide, as mandated by the Regional Act, a value of reserves credit for the reserves provided to the system by BPA's ability to interrupt service to the DSI's.

O. Public Counsel

Issue #1

Should BPA's rates include revenue to fund a consumer counsel?

Summary of Comments

One participant complained that BPA has not provided a counsel for the public consumer. The participant stated that the issues in a rate proceeding are exceedingly complex, and the general public has not been provided a counsel who can intervene or actively represent them. The commentor maintained that BPA should be able to provide funding for a consumer counsel to represent residential and small commercial ratepayers.

Evaluation of Comments

The issues in any given rate case are very complex and frequently difficult for the nontechnical person to understand. However, it is not certain that this problem would be adequately addressed by funding a public counsel. It would be difficult, if not impossible, to assure that a public counsel would fairly and accurately reflect all the diverse interests in the region. The region's ratepayers are already paying for utility and utility association representation in BPA's rate proceedings.

BPA's existing public participation policy and its means for carrying out the requirements of section 7(i) of the Regional Act are dynamic. BPA attempts to provide for the widest possible participation by the public in policy development as well as rate proceedings through the wide dissemination of lay language informational material and information/comment public meetings. The interests of the public are represented via utility participation in the formal rate proceedings, as well as through individual comments offered at the two sets of public rate hearings held throughout the Region and letters and telephone calls received by BPA's Office of Public Involvement. In addition, diverse ratepayer interests may be and have been granted formal party status in BPA's rate proceedings; e.g., Irate Ratepayers, Forelaws on Board, POWER, Southwestern Oregon Community Action Committee, Inc., and the Washington State Farm Bureau.

Decision

BPA does not plan to use ratepayer funds to provide funding for a public or consumer counsel. BPA will, however, continue to pursue public participation and representation in BPA activities through its Public Involvement Office. BPA welcomes constructive suggestions from the public on how to make this process more meaningful and responsive to the needs of the public.

P. Supply System Adjustment Clause

Issue #1

Should BPA not adopt the Supply System Adjustment Clause?

Summary of Comments

One participant has recommended that the Supply System Adjustment Clause be removed from BPA's rate proposal. He states that the adjustment clause, which permits BPA to automatically increase its rates without a rate proceeding if Supply System costs are higher than predicted, has never been mentioned in the hearings or press, and is dangerous in a region that is trying to control power rates.

Evaluation of Comments

During the past few years BPA's revenues have been significantly lower than forecast and have not been adequate to recover all repayment obligations due in the given years. BPA has had to defer interest payments to the U.S. Treasury and has not been able to make planned amortization payments. Failure of BPA to make planned payments on schedule also places a greater burden on future ratepayers.

BPA is taking a number of steps to address BPA's revenue stability problems. One of these is to propose implementation of a Supply System Adjustment Clause. In the past, actual Supply System costs have exceeded forecast costs used to develop a revenue forecast for ratemaking purposes. BPA's proposed Supply System Adjustment Clause will allow for an adjustment to be made effective July 1, 1984, if the actual OY 1984 Supply System net funding requirement or the OY 1985 Supply System Annual Budget for Projects 1, 2, and 3 differs from the costs included in the revenue requirement for those years.

Prior to implementing the Supply System Adjustment Clause, notice would be provided regarding changes in Supply System costs and the resulting rate adjustment. BPA would provide opportunity for public comment on the calculation of the adjustment. BPA would evaluate the comments before implementing the final adjustment.

Decision

BPA is including the Supply System Adjustment Clause in the Priority Firm power and Firm Capacity rates. Prior to implementation of the adjustment, BPA will provide testimony and witnesses regarding the calculation of the adjustment.

Q. Seasonal Adjustment

Issue #1

Should BPA's rate proposal be seasonal in structure?

Summary of Comments

Three participants stated that BPA's rate increase is not 27 percent as announced, but rather 20 percent in the summer and 35 percent in the winter. They complain that this has a severe impact on residential customers.

Evaluation of Comments

Seasonal differences in BPA's rates reflect many aspects of the process whereby rates are set. The most important general cause of seasonally differentiated rates is the imbalance of loads and resources through the operating year. Firm loads on BPA's system are heaviest in winter and lightest in summer. Hydro resources depend on the flow of water, which is heaviest in the spring and early summer and lightest in early fall. This imbalance means that BPA experiences varying risks of outage over the year, and also must store water during heavy runoff that can be used to produce electricity during months of light runoff. Storing water and avoiding outages both cause specific costs, which are allocated to those customers who cause these activities. This means that winter consumption costs more than summer consumption. Thus, winter rates tend to be higher than summer rates.

Decision

BPA has carefully studied and analyzed the seasonal pattern of its costs. The purposes of both equity and economic efficiency are fostered by seasonal differentiation of rates. Those loads that cause greater costs are charged higher rates. Consumers are provided the information that extra winter consumption costs more to serve than does extra summer consumption. Consumers who can shift existing or potential loads thus can identify where load growth would be cheaper. BPA has implemented this pattern in the past and will continue to do so for this rate period.

R. Northern Intertie

Issue #1

Should the Northern Intertie be separately identified as a transmission segment?

Summary of Positions

One participant stated that, in the formulation of the "Northern Intertie" transmission rate, BPA has not considered several relevant factors. These factors are (1) the original justifications which were documented by BPA for the building of these lines, (2) the historical usage of the British Columbia/BPA tie lines; (3) future firm wheeling and storage transactions which will be beneficial to BPA and 17 other U.S.A. utilities who have generation on the Columbia River; (4) the Nelway to Boundary tie development which already is completely paid; (5) the Northern Intertie concept will restrict transactions between British Columbia and any U.S.A. utility other than BPA, and (6) the difference between this intertie and other interties. B.C. Hydro, Letter, 7-28-83.

Evaluation and BPA Decision

Please refer to Chapter VII, Section H.

CHAPTER XI

SUMMARY OF CONCLUSIONS

A. The proposed rate schedules have been designed to encourage the widest possible diversified use of electric energy, consistent with all statutory requirements, by providing rates for a wide range of services.

B. These rate schedules provide uniform rates within a particular customer class and type of service.

C. The proposed rate schedules encourage the equitable distribution of the electric energy developed at the Bonneville Project by fairly allocating the costs identified in BPA's Revenue Requirement Study, COSA and TDLRIC Analysis. The proposed rates reflect the results of these studies, but also have been modified by the needs for conservation, efficiency, equity, ease of administration, continuity and legal requirements identified in BPA's WPRDS.

D. As demonstrated by the final Revenue Requirement Study, the proposed rates recover the costs associated with the production, acquisition, conservation, and transmission of electric energy and capacity, including amortization of the capital investment, interest on this investment, and all annual operating costs associated with the Federal projects and acquired power, including irrigation costs required to be paid out of power revenues and other costs and expenses incurred under appropriate provisions of law. The proposed rates provide revenues sufficient to repay when due, the principal, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to the Federal Columbia River Transmission System Act and to establish and maintain reserve and other funds connected with these bonds.

E. As demonstrated by the initial and final Revenue Requirement Studies, BPA needs a wholesale power rate increase to repay all of its obligations. The proposed rates, as demonstrated by those studies, overall will provide the lowest possible rates to consumers, allowable by law, consistent with sound business principles.

F. The proposed rates, as demonstrated by the Revenue Requirement Study, will be sufficient to allow the Administrator to make payments to the credit of the reclamation funds required to be made by law, but will not provide for payment beyond the amounts required to be repaid from power revenues for these projects.

G. The proposed rates will provide sufficient revenue to repay the Federal investment for generation within 50 years following each unit's being placed into service.

H. The amortization of reclamation projects that BPA is required to repay from net revenues will not average more than $30,000,000 per year for any consecutive 20-year period and these reclamation projects have not been scheduled in a manner that would result in exceeding that 20-year average figure.

I. The recovery of the cost of the transmission system, as demonstrated by the segmented analysis of transmission costs contained in the COSA, is equitably allocated between Federal and non-Federal power utilizing BPA's transmission system.

J. The proposed rates for secondary energy have been established with regard to an equitable sharing of the benefits of these sales between the regions involved in the sales.

K. The Hearing Officer has performed commendably his duties under section 7(i) of the Regional Act to assure that a full and fair evidentiary hearing, open to all interested persons, has been conducted on all issues relevant to BPA's wholesale power and transmission rates. All parties have been given every reasonable opportunity to engage in discovery, present testimony, engage in cross-examination of adverse witnesses, present oral argument, and submit briefs.

Based upon the foregoing, I hereby adopt as Bonneville Power Administration's final rate proposal the attached wholesale power and transmission rate schedules.

Issued at Portland, Oregon this 29th day of September 1983.

Peter T. Johnson

Peter T. Johnson
Administrator

APPENDIX

APPENDIX A

PARTY ABBREVIATIONS

Arco Metals	ARCO
Association of Public Agency Customers	APAC
Bonneville Power Administration	BPA
CP National Corp	CPN
California Energy Commission	CEC
California PUC	CPUC
Central Lincoln PUD	Cen Lin
Chelan County PUD	Chelan
Chelan, Douglas, and Grant County PUD's	Chel,Doug&Grt
Columbia River Inter-Tribal Fish Commission	CRITFC
Cowlitz PUD	Cowl
Direct Service Industries	DSI
Douglas County PUD	Doug
Forelaws on Board	FOB
Grant PUD	Grt
Hanna Nickel	Hanna
Idaho Public Utilities Commission	IPUC
Intalco Aluminum Corp	Intalco
Intercompany Pool	ICP
Los Angeles Department of Water & Power	LADWP
Montana Public Utilities Commission	MPUC
National Marine Fisheries Service	NMFS
Non-Generating Group	Non-Gen
Northwest Environmental Defense Center	NEDC
Northwest Generating Utilities	NGU
Northwest Irrigation Utilities	NIU
Northwest Utilities	NWU
Oregon Department of Agriculture	ODA
Oregon Public Utilities Commission	OPUC
Pacific Gas & Electric	PG&E
Pacific Northwest Generating Company	PNGC
Pacific Power & Light Company	PP&L
Portland General Electric Company	PGE
Public Generating Group	PGP
Public Power Council	PPC
Puget Sound Power & Light	PSP&L
San Diego Gas & Electric	SDG&E
Seattle City Light	SCL
Snohomish County PUD	Snoh
Southern California Edison	SCE
State of California	St. of Ca.
Tacoma City Light	TCL
U.S. Congressional Representative James Weaver	Congress
Utah Power & Light	UP&L
Washington State Farm Bureau	WSFB
Washington Utilities & Transportation Commission	WU&TC
Western Washington PUD Group	WWPUD

APPENDIX B
LIST OF 1983 WHOLESALE AND TRANSMISSION RATE HEARINGS
PARTIES' WITNESSES AND REPRESENTATIVES

INDIVIDUAL	REPRESENTING	INDIVIDUAL	REPRESENTING
Ahrenholtz, Don	WSFB	Einarsson, Gosta	Doug
Albertson, Charles	NMFS	Engstrom, Wesley	APAC
Alcantar, Michael	DSI	Evans, Dale	NMFS
Alexanderson, Alvin	PGE		
Allcock, Charles	NWU	Fairchild, Peter G.	CPUC
Armentrout, William	DSI	Fiddler, Richard	SCL
Ater, Jonathan	DSI	Floyd, Don	ODA
		Foianini, Ray	Chel
		Frazee, Mark	SCE
Bakalian, Allan	NEDC	Furman, Donald	PGE
Ballbach, Daniel	PSP&L		
Baker, Robert	APAC		
Barkeley, Donald	IPC	Garman, Gerald	PGP/NGU
Barker, William	TCL	Garten, Allan	APAC
Barry III, David	SCE	Gordon, Robert	UP&L
Baxendale, James	PGE	Gould, John Wiley	CPN
Baxendale, Richard	PPC	Graham, Paul	OPUC
Bennett, Barry	OPUC	Grey, Robert	Hanna
Benfield, Ronald	Cen Lin		
Bidwell, Richard	DSI		
Bischof, John	ARCO	Hall, Robert	Intalco
Blevins, Kenneth	DSI	Hellman, Marc	OPUC
Bodi, Lorraine	NMFS	Hirschfeld, Clyde	SCE
Bubenik, Mark	TCL	Hittle, David	NIU
Buckingham, Richard	PG&E	Holt, Roger	LADWP
Bury, John R.	SCE	Holtzapple, Jack	DSI
		Huffman, James	Chel
Carter, George	DSI	Hurless, Clayton	PNGC
Carver, Philip	OPUC	Hutchison, Coe	WWPUD
Chamberlain, William	CEC		
Childs, Dave	ODA		
Cook, Harold	APAC	Jacklin, Pamela	PP&L
Cooley, Frank	SCE	Johnson, Leayesh	PNGC
Cox, Judith	NWU	Jones, Aaron	PNGC
Crisson, Mark	PGP		
Czepiel, Thomas	APAC		
		Kalcic, Bryan	APAC
Dahlke, Gary	WWPUD	Karavitas, G.	TCL
Davis, Craig	Intalco	Kari, Donald	PSP&L
Dodson, Mark	DSI	Kavanaugh, David	DSI
Dompier, Douglas	CRITFC	Kellerman, Larry	ICP
Dorran, Russ	ODA	Kerr, Janice E.	CPUC
Drazen, Mark	DSI	Knight, D.H.	PSP&L
Durant, Richard	SCE	Knitter, Keith	PGP
		Krahmer, Cal	ODA
		Kuns, Douglas	ICP
		Kunzman, Leonard	ODA

INDIVIDUAL	REPRESENTING
Lamb, Frank	ODA
Larsen, Alan S.	PGP
Lauckhart, Richard J.	ICP
Lawson, Gary W.	WWPUD
Lee, Allen	ODA
L'Heureux, Andre	IDA
Lindsay, William L.	SCE
Lisbakken, R. B.	NWU
Little, Douglas S.	UP&L
Locke, Edward	DSI
Lothrop, Rod	CRITFC
Lubking, Eugene W.	Chel,Doug&Grt /PGP
Lyman, Peter	NWU
Marbet, Lloyd	FOB
Mattson, Bert	CPUC
Mayson, Jack	DSI
McArthur-Phillips, M.	APAC
McCullough, Robert	NWU
McGrane, John	SCE
McKenzie, A. Kirk	PG&E
McKinney, Robert L.	Cowl
McMahan, John	Grt
Meek, Daniel	WEAVER
Mertsching, Charles	Cowl
Meyer, David J.	WWP
Mizer, Bruce E.	DSI
Moke, E.	Hanna
Morganthaler, George	DSI
Moxness, Kay	Cen Lin
Muller, David	WWPUD
Mundorf, Terence L.	WWPUD
Nadel, Joseph	PNGC
Noyes, Kent	LADWP
Oliviera, Ronald	OPUC
O'Meara, Kevin P.	PPC/NWU
O'Rielly, Gary L.	APAC
Opatrny, Carol C.	PGP
Opitz, William J.	MPUC
Ordin, Andrea	St. of Ca.
Owens, Douglas N.	WU&TC
Parks, Richard	NWU
Parmesano, Hethie	LADWP
Peseau, Dennis	DSI
Poth, Harry A.	Intalco
Prekeges, Gregory	ICP

INDIVIDUAL	REPRESENTING
Reading, Don	IPUC
Redman, Eric	DSI
Russell, Lance W.	PPC/WWPUD
Saleba, Gary	WWPUD
Saxton, Ronald L.	DSI
Schneider, Robert	WWPUD
Schoenbeck, Donald	DSI
Schultz, Merrill S.	NGU/NWU
Selmi, Daniel P.	St. of Ca.
Shanker, Roy J.	APAC
Sherline, Lee S.	MPC
Simpson, J. Calvin	CPUC
Simpson, Robert E.	WU&TC
Sirvaitis, Ron	ICP/NWU/PP&L
Slade, David	NEDC
Smith, Stephen	NMFS
Sprayberry, William D.	PPC
Springer, Ted C.	PNGC/NIU
Strong, R. Blair	MPC
Strong, Michael G.	SDG&E
Sullivan, William R.	Non-Gen
Strumwasser, Michael	St. of Ca.
Sunday, Alexander	PGP
Taylor, Paulette	Intalco
Thompson, Richard	Non-Gen
Tompkins, Patricia	IPUC
Torvend, Palmer	ODA
Tucker, James F.	APAC
Uraguchi, Maseo	LADWP
Van de Kamp, John K.	St. of Ca.
Waldron, Jay T.	PGP
Walsh, James F.	MPC
Walters, Myrna J.	IPUC
Wapato, Tim S.	CRITFC
Weaver, William S.	PSP&L
Weaver, James	Congress
Wedge, Herbert D.	Hanna
Whaley, Jay	PGP
White, Keith	ICP/PGE
Wilcox, Brett	DSI
Williams, Claude	ODA
Williams, Walter L.	SCL
Wilson, John L.	DSI
Wilson, Robert C.	ICP/NWU
Wollenberg, Richard P.	APAC
Wolverton, Lincoln	PPC/NWU
Wood, Marcus A.	PP&L

APPENDIX C

A. Participants Commenting on
BPA's 1983 Wholesale Power and Transmission Rate Proposal

Participants Burley, Idaho Public Hearings

Individual	Representing
Aikele, Juel	irrigator
Anderson, Hal T.	irrigator
Beck, Bruce	irrigator
Black, Jay L.	irrigator
*Burbank, Larry	Rural Electric Co.
Christianson, Chester	self
Drake, Asa J.	irrigator
Egbert, Gerald	irrigator
Harrison, Danial H.	self
Inouye, Mits	irrigator
Johnson, Don	irrigator
Lloyd, Stan	irrigator
Newcomb, Bruce	Southside Electric
Norman, Newell	irrigator
Parkinson, Bob	irrigator
Penfold, Don	irrigator
Reed, Gale A.	irrigator
Reese, Dallin	Idaho Wheat Commission
Ripplinger, Weston	irrigator
Searle, Kent	irrigator
Watrons, Robert	self
Whitton, Mayor W. F.	City of Rupert
*Wickham, Calvin	Fall River Rural Electric Coop
Williams, Connie	self
Woodbury, Orin	irrigator

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants at Eugene, Oregon Public Hearings

Individual	Representing
Boies, JoAnne	self
Braaten, E. N.	self
Christie, Ed	Concerned Citizens of Oregon
Davis, Dan	labor
Foland, Skip	labor
Jensen, Peter	self
Longfellow, John	self
Ramsey, Taylor	Eugene Area Chamber of Commerce
Sadler, Sam	self
Solitz, Dan	self
Stolle, Georgeana	Concerned Citizens of Oregon
Walter, Fred	self

Participants Lynnwood, Washington Public Hearing

Individual	Representing
*Barnes, Gordon	DSI
Berkley, Lori	self
Bertrand, Dan	indust wkr.
Britt, Larry	labor
Egnor, Terry	self
Gerr, Wm. T.	self
Groskopf, Daniel	Energy Mgt. Students Assoc.
Haines, Helen	Snohomish Co. PUD, Rate Adv. Comm.
Kusler, Don	self
Laman, Bruce	self
McLellan, Larry	Committee of 1700
Richardson, Everett	self
Rosier, Gordon	self
Sather, Dennis	labor
Smith, Steven	self
Walsh, Deborah	Committee of 1700

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants at Missoula, Montana Public Hearings

Individual	Representing
Axtell, Murl	Flathead Irrigation Proj.Bertrand, Dan
	labor
Brown, Arlene Ward	Missoula County Commissioners
Corbett, Dennis	labor
Jensen, Ray	Flathead Irrigation Project
*Mason, Gary D.	Ravalli County Electric CO-OP
Mills, George	labor
Nelson, Joe	Flathead Irrigation Project

Participants Portland, Oregon Public Hearing

Individual	Representing
Bennet, Stephen L.	self
Brumitt, Jim	labor
Edgington, Richard	labor
Fadman, Peggy	The Dalles Chamber of Commerce
Fletcher, Jim	labor
Foland, Walter	NW Labor Coalition on Energy
Heutte, Fred	Solar Oregon Lobby
Nelson, Don	labor
Saunders, Robert	NW Labor Coalition on Energy
Smith, Ted	labor
Williams, E. D.	self

Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants at Richland, Washington Public Hearings

Individual	Representing
Akey, Dan	irrigator
Akins, Hadley	self
Akins, Hadley	U.S. Nat'l Bank of Oregon
Albertin, Fred	irrigator
Anders, John	indust. wkr.
Baumann, Kirk	irrigator
Beightol, Dick	irrigator
Beightol, Richard	irrigator
Bennett, Bill	irrigator
Bertrand, Dan	industr. wkr.
Brady, Margaret	self
Brewington, Clark C.	irrigator
Britt, Larry	indust. wkr.
Cannaro, Ruth	irrigator
Childs, David	irrigator
Chvatal, Pat	irrigator
Clouse, Phil	self
Didier, Alice	Wash. State Farm Bureau
Ellis, Keith	Wash. Dept. of Agri.
Forry, Mayor Cyrus	City of Goldendale, WA
Fountain, Duane	irrigator
Gulick, Peggy	self
Henry, Robert	self
Henry, Robert T.	Concerned Ratepayers' Assn.
Hooper, Jeff	irrigator
Howe, Calvin	self
Hsieh, Jack	irrigator
Hutchinson, Virgil	labor
Irate Rate Paying Farmer	irrigator
*Jones, Aaron	Big Bend Elec. Coop
Kangas, Arnold	self
Kerby, Gene	irrigator
Kerby, Gene	self
Lacy, Don	indust. wkr.
Langenwalter, Allan	Hermiston Chamber of Commerce
Larsen, Anker	irrigator
Lawr, W.T.	self
Maulden, Carla	irrigator
Meklenbacher, Alan	irrigator
Merrill, Ed	self
Mills, George	labor
Nakanura, Hisahi	Franklin Co. Farm Bureau
O'Connor, James	self
Padberg, Marvin	irrigator
Patch, Paul	irrigator
Paxton, Keith	indust. wkr.

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants at Richland, Washington Public Hearings (Continued)

Individual	Representing
Peterson, Myron	irrigator
Peterson, Myron	irrigator
Pfeifer, Joe	irrigator
Poulson, Mike	self
Ransom, Mr. & Mrs. Bob	irrigator
Shook, Carroll	labor
Smith, Russell	irrigator
Speed, N. A.	self
Speed, Nicoles, A.	self
Szymkowski, Charles J.	irrigator
T&R Farms	irrigator
Tandberg, Pete	Comm. of 1700
Taylor, Linda	Comm. of 1700
Thackray, Kim	Comm. of 1700
Thomas, Fran	irrigator
Thomas, Fran	irrigator
Tucker, Brok	irrigator
Tucker, Pat	irrigator
Walkey, Van I.	irrigator
Walkley, Evelyn	irrigator
Wallace, Bob	self
Weidert, John	irrigator
Willnes, Arnold	indust. wkr.
Wistisen, Martin	self
Yeager, Dean	indust. wkr.

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants Seattle, Washington Public Hearing

Individual	Representing
Allen, George	self
Berkley, Lou	Fair Use of Snohomish Energy
Bertrand, Dan	Union Coalition on Energy
Dinnihan, Robert	self
Gray, Thomas	self
Gregory, Regina	self
Lazar, Jim	Fair Electric Rates Now
Menger, Ross	self
Newcomb, Joe	labor
Pennington, Karl	Fair Use of Snohomish Energy
Rosier, Gordon	Fair Use of Snohomish Energy
Rosted, Ross	self
Rush, Warren D.	self
Sansom, Donnie	self
Solom, Kristy	self
Stanton, Mark	self
*Whelan, John	Mason Co. PUD #3
White, Carol	self

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants at Spokane, Washington Public Hearings

Individual	Representing
Ames, Clarence	Committee of 1700
Bolenues, Robert	Lincoln County Farm Bureau
Coon, Dick	Adams County Board of Commissioners
Coulson, Jim	self
Ellis, Keith	Wash. Dept. of Agriculture
Fink, Alvin	self
Gaffney, John M.	self
Galbreath, Gary	self
Gering, Gayle	Washington Assn. of Wheat Growers
Graedel, Bill	self
*Heitdman, Dick	Lincoln Electric Coop
Homberg, Lamar, D.	self
Leinen, John	labor
Link, Alan	labor
Peterson, Lawrence	self
Phillips, Reid	self
Pordon, Dave	self
Rettkowski, Gale	self
Ruff, Steven	labor
*Slatt, Vincent P.	Inland Power & Light Co.
Smith, Gordon A. A.	self
Stanley, Larry	self
Templin, Chester	self
*Wagner, Byron	Big Bend Electric Coop
Williams, Keville	labor
Yuse, Frank	self

Participants Tacoma, Washington Public Hearing

Individual	Representing
*Agnew, John	DSI
Chementi, Mike	labor
Childs, John	indust. wkr.
Clayburg, Keity	labor
Doan, Charles	Port of Tacoma
Eagling, Tom	labor
Griffin, Dennis	labor
Hurless, Harry D.	self
McLane, Gerald	self
Meister, Henry	self
Mills, George	labor
Smith, H. O.	labor
Thompson, Joe	labor
Wheeler, Larry	labor

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

Participants Vancouver, Washington Public Hearing

Individual	Representing
Anderson, Judith	self
Bennett, Stephan	self
Bonneau, Ron	self
Brumitt, Jim	labor
Downey, Merrill	self
Edgington, Dick	labor
Griffing, Milton	self
Hillbranz, John	self
Hurless, Harry D.	self
Jaggard, Norton	self
King, Goff, Hal	self
Lanphier, Del	self
Lee, Art	self
McLennan, Larry	Committee of 1700
Nelson, Don	labor
Nyland, Richard	Clark Co. PUD Citizens Rate Advisory Comm.
Sauders, Robert	labor
Sheehan, William	self
Thompson, Joe	labor
Uhrig, Phil	self
Ullmer, Derald	self
Walker, Dave	self
Ward, Dorothy	self
Weber, Mayor Dennis	City of Longview
Wheeler, Larry	labor
Winton, Monty	self
Wochter, Robert	self
Wulff, Rollie	self

*Denotes commenter who is represented in the rate case as a party; These comments were not included within those of the participants.

APPENDIX C

B. Participants Commenting on
BPA's 1983 Wholesale Power and Transmission Rate Proposal
Comments Made by Letters

Individual	Representing
Abbott, William D.	self
Ackerson, Gary R.	indust. wkr.
Adams Carol L.	self
Adams, Dordena	self
Adams, Fred J.	indust. wkr.
Adams, Harry R.	self
Adams, Jeffry A.	indust. wkr.
Adams, Steve	self
Agnew, John E.	indust. wkr.
Ague, Ellen	self
Ague, Ralph	self
Ahstull, Mike	self
Akerman, Robert W.	self
Akins, Hadley C.	U.S. Nat'l Bank of Ore.
Aklestad, Gary D.	Montana Senator
Alaniz, Leonel G.	indust. wkr.
Albright, Linda	self
Albro, Gary R.	indust. wkr.
Alexander, James A.	self
Alexander, Joe	self
Allen, Amos	self
Allen, J. Lorna	self
Allen, Jerry L.	self
Allen, Michael L.	indust. wkr.
Allen, Michael W.	indust. wkr.
Allen, Roger E.	indust. wkr.
Allikkala, L. (Mrs.)	self
Allison, Darlene, L.	indust. wkr.
Alvardo, Raul	indust. wkr.
Ames, Susan	self
Amundson, Robert O.	indust. wkr.
Anderson, Albert D.	indust. wkr.
Anderson, Brad D.	indust. wkr.
Anderson, Bradford M.	indust. wkr.
Anderson, C. W.	indust. wkr.
Anderson, Clifford	irrigator
Anderson, Ernest P.	indust. wkr.
Anderson, Fred	indust. wkr.
Anderson, Gary	self
Anderson, Howard C.	indust. wkr.
Anderson, Jack & Debbie	indust. wkr.
Anderson, Linda	indust. wkr.
Anderson, Randy A.	indust. wkr.
Anderson, Richard	self
Anderson, Verner	Oregon Representative
Applington, Melvin R.	indust. wkr.
Archuleta, Robert	indust. wkr.
Arends, Raymond (Mr. & Mrs.)	self
Arestad, Greg	self
Arevalo, V. Joe	indust. wkr.
Argue, Dorothy L.	self
Armitage, Cecil	indust. wkr.
Arnold, Herbert R.	indust. wkr.
Arp, Richard (Mr. & Mrs.)	self
Arthur, Richard	indust. wkr.
Ashcraft, Walter C. (Mrs.)	self
Assink, Larry L.	indust. wkr.
Atiyeh, Victor	self
Atwood, Jerry L.	indust. wkr.
Atwood, William C.	indust. wkr.
Austin, James	indust. wkr.
Babb, Alfred J.	self
Babb, Emma D.	self
Babbitt, Lance	indust. wkr.
Babcock, Victor M.	indust. wkr.
Bachmeier, Adam & Kathryn	self
Bachmeier, Edward	irrigator
Bagwell, Clifford	self
Bailey, Duane	self
Bailey, Janet E.	self
Bailey, Ronald P.	indust. wkr.
Bailie, L. W. (Mr. & Mrs.)	self
Bailie, Leonard W.	self
Baker, Bonnie	self
Baker, Guy E.	self
Baker, Ronald D.	indust. wkr.
Baker, William L.	self
Bakker, C. Duane	indust. wkr.
Baldie, Bruce	indust. wkr.
Ballensky, Merlin	self
Ballew, Wayne J.	indust. wkr.
Bane, Buel H.	self
Bane, George, E.	indust. wkr.
Banstad, Greg E.	indust. wkr.
Bard, Donald L.	indust. wkr.
Bardipeg, Les	self
Bargas, John	self
Bargas, Joni	self
Bargas, Ruby	self
Bargas, Toni	self
Barker, Peter	indust. wkr.
Barnes, Robert A.	self
Barnett, Joseph A.	indust. wkr.
Barney, Marion (Mrs.)	self
Barr, Edgar & Helen	self
Barrett, Thomas	indust. wkr.
Barrigan, Al	self
Barrigan, Alan (Mrs.)	self
Barrigan, Dennis	self
Barrigan, Karle	self
Barrus, William R.	self
Barstad, Harvey	self
Bartelds, George S.	indust. wkr.
Bartell, Jack	indust. wkr.
Bartell, Michael A.	self
Bartell, Shirley	self
Bartlett, David	indust. wkr.
Bartosch, Joe E.	self
Baska, Steve and Diana	self
Bass, Howard J.	indust. wkr.
Batty, A. L.	indust. wkr.
*Baumgartner, David S.	Hanna Nickel Smelting Co.
Bavary, B. R.	self
Beale, Phil (Mrs.)	self
Beall, Marsh F.	self
Beam, Jay A.	self
Beaman, Bruce (4 letters)	self
Beard, Louis, Jr.	self
Beasley, Ernest E.	indust. wkr.
Beatty, Harold E.	indust. wkr.
Beckstrand, Del	self
Beebe, George	self
Beebe, Kathy	self
Beebe, Merle M.	indust. wkr.
Beebe, Michael L.	indust. wkr.
Behrmann, Otto	self
Belanger, Rodrique M.	indust. wkr.
Belida, Vernon	self
Belida, Vernon (Mr. & Mrs.)	self
Bell, Alan F.	indust. wkr.
Bell, J.C.	self
Bell, William, G.	self
Bellamy, Fred	self
Belleisle, Brian L.	self
Belleisle, Kenneth H.	indust. wkr.
Belleisle, Sharon	self

* Denotes Commenter who is represented in the rate case as a party; these comments were not included within those of the participants

APPENDIX C

Individual	Representing	Individual	Representing
Bena, Dan	Indust. wkr.	Brister, Thomas J.	Indust. wkr.
Bender, Carl W.	Indust. wkr.	Britt, Lawrence R.	self
Bennett, Carl	Indust. wkr.	Broadbent	self
Bennett, Clarence M.	self	Broadwater, Eugene, S.	self
Bennum, Frank B.	Indust. wkr.	Broeckel, Walt & Lois	self
Berg, Gary L.	self	Brokaw, Kevin P.	Indust. wkr.
Bergeson, Donald E.	Indust. wkr.	Brooks, Mary	self
Berkley, Susan	self	Brown, Bruce M. (Mrs.)	self
Bernard, Richard T.	Indust. wkr.	Brown, Deltha	self
Bernards, Richard M. & Sandra K.	self	Brown, Donald G.	Indust. wkr.
Bernards, Rovert E. (Mrs.)	Indust. wkr.	Brown, John E. & Family	Indust. wkr.
Bernardy, Lloyd	Indust. wkr.	Brown, John P.	Indust. wkr.
Bernier, Mary D.	self	Brown, Larry G.	Indust. wkr.
Berrmann, Otto	self	Brown, Lawrence H.	self
Best, Charlie E.	Indust. wkr.	Brown, Linda	self
Beuch, Carol S.	self	Brown, Linda	self
Bezona, Jon W.	Indust. wkr.	Brown, Linda	self
Bice, Travis G.	Indust. wkr.	Brown, Sandy (2 letters)	Indust. wkr.
Bickel, H.	self	Browning (Mrs.)	self
Biebe, Harry	self	Browning, Carl E.	Indust. wkr.
Bigger, Evalyn	self	Browning, Robert (Mr. & Mrs.)	self
Biles, Lael G.	Indust. wkr.	Browning, Robert L.	self
Billington, John	Indust. wkr.	Browning, Travis	self
Bindy, Everett	self	Bruce, James E.	Idaho Power Co.
Bingham, Vernon W.	Indust. wkr.	Bruch, Carol S.	self
Birchall, Larry A.	Indust. wkr.	Bruch, Donald S.	Indust. wkr.
Bird, Dourland R.	Indust. wkr.	Brunsdon, Harry L.	self
Bird, Raymond R.	Indust. wkr.	Brush, Jerry	Indust. wkr.
Bird, Robert	Indust. wkr.	Bryant, John C. (Mr. & Mrs.)	self
Birdsey, Jerry	Indust. wkr.	Buchara, Pete	self
Bisset, James	Indust. wkr.	Budde, Eugene L.	Indust. wkr.
Bittorfs, Charles C.	self	Buehler, Hans	Irrigator
Black, Arlen L.	Indust. wkr.	Burbank, Alice M.	Indust. wkr.
Black, Kenneth P.	self	Burbank, J. P.	Indust. wkr.
Blake, Dana M.	self	Burbon, Joseph	Indust. wkr.
Blake, Jack L.	Indust. wkr.	Burke, Roy	self
Blake, Tom	self	Burns, Mike	self
Block, Janet	self	Burrell, Norman J.	Indust. wkr.
Blocketer, David A.	Indust. wkr.	Burril, Charles C.	Indust. wkr.
Bock, Ronald N.	Indust. wkr.	Buss, Marvin E	Indust. wkr.
Bode, Daniel P.	Indust. wkr.	Bybee, David L.	Indust. wkr.
Bohannon, D. E.	self	Byer, David	Indust. wkr.
Bohrer, Sharon K.	self	Byrans, Bill	self
Boice, Michael K.	Indust. wkr.	Byrd, Carter L.	Indust. wkr.
Boler, Truman O.	self	Cain, James	self
Bollinger, Thomas B.	Indust. wkr.	Caldwell, Harvey H.	self
Bollinger, A. Paul	Indust. wkr.	Calkins, Burton D.	self
Bonner, Robert W.	B.C. Hydro	Callen, H. W.	self
Bonton, Greg	Indust. wkr.	Campbell, Julee A	self.
Bookbinder, Donald	Indust. wkr.	Campbell, Loren J.	self
Booren, Jeffrey	self	Campbell, Ron (Mr. & Mrs.)	self
Bordarrampe, Sherman	Indust. wkr.	Campbell, Vern H.	Indust. wkr.
Bouska, Joe	Indust. wkr.	Campbell, William (Mrs.)	self
Boutwell, Vernon E.	Indust. wkr.	Cannon, David	self
Bovey, Ralph	Indust. wkr.	Cantu, Pete	Indust. wkr.
Bowman, Rupert O.	Indust. wkr.	Caple, Verl R.	self
Bowyer, Steve	Indust. wkr.	Capps, Robert J.	Indust. wkr.
Boyette, V.	self	Capps, Robert J. (Mrs.)	self
Bozzel, Ron	Indust. wkr.	Card, Jerry	self
Bradford, Donald R.	self	Carlson, Leland D.	Indust. wkr.
Bradley, Larry L.	Indust. wkr.	Carlson, M. (Mrs.)	self
Bradshaw, Gary	self	Carlson, Walter E.	self
Brandt, Gilbert C.	self	Caron, Cindi	Indust. wkr.
Brauburger, Carlin L.	self	Caron, Norman W.	Indust. wkr.
Brauburger, Holly J.	self	Carr, Esequiel III	Indust. wkr.
Braun, Sandy J.	self	Carrico, Jay	self
Bray Jr., John W.	self	Carter, Berneice	Indust. wkr.
Bray, Suzanne L.	self	Carter, D. Kay (Mrs.)	self
Brayton, Gary R.	Indust. wkr.	Carter, John (2 letters)	Irrigator
Breazile, Dewey L.	self	Carter, Phyllis	self
Bridenbecker, Don	self	Carter, Richard G.	Indust. wkr.
Bridgefarmer, Marjorie L.	self	Carter, W. G.	Indust. wkr.
Briery, Jerry E.	Indust. wkr.	Casey, Clark W.	Indust. wkr.
Brincefield, C. G.	Indust. wkr.	Casey, Darlene	self
Brink, John D. (2 letters)	Indust. wkr.	Casey, R. Verne	self
Brionez, Armando Jr.	Indust. wkr.	Cashen, Goldie	Irate Rate Payers

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APPENDIX C

Individual	Representing
Cassal, Kenneth L.	Indust. wkr.
Casswell, S. J.	Indust. wkr.
Cast, William J.	Indust. wkr.
Castillo, Alfredo	Indust. wkr.
Castillo, Humberto C.	Indust. wkr.
Castle, Edwin A.	Indust. wkr.
Cates, Michael	self
Caudill, Gene	self
Caughell, William E.	Indust. wkr.
Caughey, Colvin	self
Ceciliani, Steven C.	Indust. wkr.
Chambers, Allen R.	self
Chambers, Irma	self
Chapin, S. Diane	Indust. wkr.
Chapman, Gordon E.	self
Chapman, Raymond G.	Indust. wkr.
Chase, David L.	self
Cheney, John D.	Indust. wkr.
Cheney, Robert	Indust. wkr.
Chervenock, Ronald D.	Indust. wkr.
Childer, Jack D.	self
Childs, Marshall	Indust. wkr.
Chiles, Robert D. II	self
Chinn, Rocky M.	self
Christensen, Jeff	City of Corvallis
Christianson, H. W.	self
Christofferson, Thomas A.	Indust. wkr.
Christopher, John A (Mr. & Mrs.)	self
Cladouhos, Janice	self
Clark, Eugene L.	Indust. wkr.
Clark, Harold	self
Clark, James Edwin	Indust. wkr.
Clark, Ken & Debra	self
Clark, Mike (Mr. & Mrs.)	self
Clark, P.E.	Irrigator
Clark, Shirley	self
Classen, Justin	self
Clauson, Paul	Indust. wkr.
Clauson, Ruth R.	self
Claybo, Denneth E.	Indust. wkr.
Clemens, Jim	Indust. wkr.
Clifton, Charles	self
Cline, Debbie	self
Cline, Deborah	self
Cline, Donald	self
Cline, Howard & Rubie	self
Cline, Roger	self
Cline, Roger Dean	self
Clizbe, Thomas R.	Indust. wkr.
Clizer, Paul	Indust. wkr.
Clunk, Robert D.	self
Cobb, Theresa	self
Cobb, Vince	self
Cochenour, David J.	self
Cochenour, Steve	Indust. wkr.
Cochran, Lance	self
Coffelt, Neil	Indust. wkr.
Coffield, Jack & Pauline	self
Colby, David & Julianne	self
Cole, Edward	self
*Cole, Robert E. (with petition)	Harney Elect. Coop
Coleman, Alice	self
Coleman, Jim	Indust. wkr.
Colen, H. W.	Indust. wkr.
Colgan, William P.	self
Collar, Keith	self
Collier, Lloyd D.	Indust. wkr.
Collier, Mike (Mr. & Mrs)	self
Collins, Andrew	Indust. wkr.
Collins, Linda L.	self
Collins, Steven R.	Indust. wkr.
Colvard, D. J.	Indust. wkr.
Combelic, Neil O.	self
Combs, Paul N.	self
Conboy, Petrard & Therese	self
Concannon, James B.	self
Conlee, G. (Mrs.)	self
Conner, Dan	self
Connolly, R. T.	self
Connor, Thomas M.	Indust. wkr.
Cook, Gene L.	Indust. wkr.
Cook, Terry B.	Indust. wkr.
Cooper, John H.	self
Cooper, Leon F. Sr.	Indust. wkr.
Corey, John	Indust. wkr.
Cosgrove, Robert F.	Indust. wkr.
Cosner Jr., Perry	Indust. wkr.
Cosner, Clinton (Mr. & Mrs.)	self
Cosner, Mary L.	self
Coulson, Jimmie T.G.	self
Cowling, Stephen P.	Indust. wkr.
Cox, Don	Indust. wkr.
Cox, Harold	Indust. wkr.
Cox, Melvin H.	self
Craig, Charles C.	Indust. wkr.
Cramer, Joe O.	Indust. wkr.
Cramer, Thomas R.	Indust. wkr.
Crape, Donald C.	Indust. wkr.
Crapser, Dear A.	Indust. wkr.
Crawford, Neil T.	Indust. wkr.
Creech, Elmo	Indust. wkr.
Creek, Billy E.	Indust. wkr.
Creek, James A.	Indust. wkr.
Crisp, Cirby R.	Indust. wkr.
Croft, Ed	self
Crouse, Charles (Mr. & Mrs.)	Indust. wkr.
Crozier, Donald M.	self
Cruikshank, Robert A.	Indust. wkr.
Culver, Raymond W.	Indust. wkr.
Cumiford, Nylene	self
Cumiford, Richard	self
Cunningham, Frances	self
Cunningham, Glen M.	Indust. wkr.
Curtright, Glenn F.	Indust. wkr.
Cyphers, Mary E.	self
Czikall, Randy	Indust. wkr.
Dahle, Timothy A.(Mr. & Mrs.) & Baggett Sr., Frank	self
Dahlgren, Mark J.	Indust. wkr.
Dailey, Robert J.	self
Dailey, Robert J. (Mr. & Mrs.)	self
Dake, Franklin D.	Indust. wkr.
Daloisio, Edward J.	Indust. wkr.
Daniel, John (2 letters)	Puget Sound Power & Light
Darkis, Jerry	Indust. wkr.
Darlington, Neil	self
Darnell, Betty	self
Davidson, Barbie	self
Davies, Frank & Elaine	self
Davis, Charles D.	Indust. wkr.
Davis, Ken	Indust. wkr.
Davis, Larry J.	Indust. wkr.
Davis, Peter	self
Davis, Ronald G.	Indust. wkr.
Davis, Ronald G.	self
Dawson, Edmund D.	Indust. wkr.
Day, Virginia L.	self
DeArment, Thomas	Indust. wkr.
DeBoer, Arthur M.	Indust. wkr.
DeHart, Alice	self
DeHart, Ray E.	self
DePoppe, Norman D.	Indust. wkr.
DeShazo, O. A.	self
Decker, Eula M.	self
Dehart's Westgate Mkt Employees	self
Delozier, Ed	self
Demaray, Dale I.	Indust. wkr.
Demaray, Jean	self
Demaray, Melinda	self
Denney, Dale W.	Indust. wkr.
Denton, Dallas	Indust. wkr.
Denton, Tawney	self

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Individual	Representing	Individual	Representing
Deschand, Darrell & Maxine	self	Emerson, Kathryn	Indust. wkr.
Deschand, Richard	self	Emley, David W.	Indust. wkr.
Deshazo, Randall J.	Indust. wkr.	Emley, Ray (Mrs.)	self
Deshazo, Steven L.	Indust. wkr.	Engels, Fred E.	Indust. wkr.
Deshazo, Thomas A.	Indust. wkr.	Engler, Dwaine E.	Indust. wkr.
Deshazo, Tim C.	Indust. wkr.	Engler, Roger D.	Indust. wkr.
Devin, Ann	self	Erickson, Clayton G.	Indust. wkr.
Dewey, Darley	self	Erickson, Dean	Indust. wkr.
Dewey, Leslie	self	Erickson, Dianne	self
Dickey, Desrie	Indust. wkr.	Erickson, Gary	Indust. wkr.
Dickmann, Doris	self	Erickson, Linda	self
Diehl, Hugh R.	Indust. wkr.	Eshuis, John	Indust. wkr.
Dillard, J. W. (Mrs.)	self	Esson, Floyd A.	Indust. wkr.
Dillard, Jack	Indust. wkr.	Esson, William S.	Indust. wkr.
Dillinger, Dwight E.	Indust. wkr.	Evans, Herb	self
Dillon, Richard R.	self	Even, William & Doris L.	Indust. wkr.
Diskin, Charles	Indust. wkr.	Ewing, Delores	Indust. wkr.
Diskin, Charles E.	Indust. wkr.	Ewing, Gene	Indust. wkr.
Dixon, Dennis L.	self	Ezell, Eddie J.	Indust. wkr.
Dixon, Mary	self	Ezelle, James	labor organization
Dixon, Mike D.	Indust. wkr.	Faaberg, Richard	Indust. wkr.
Dixon, Norman	self	Fadness, Elt & Peggy	self
Dixson, Ed	self	Fagin, Larry B.	Indust. wkr.
Dodd, Kenneth L.	Indust. wkr.	Fahey, Patrick D.	Indust. wkr.
Dodge, Burton	Indust. wkr.	Falk, Ron & Family	Indust. wkr.
Dokken, Lavora N.	self	Farms, Hess	Irrigator
Donovan, Joseph A.	self	Farrar, W. Michael	Indust. wkr.
*Dorran, Russell N.	Umatilla Elec. Coop Assoc.	Farrier, Bruce E.	Indust. wkr.
Dorr, Christine G.	Indust. wkr.	Fateley, Ron	Indust. wkr.
Dorsett, Rosemary	self	Fay, Terry L.	Indust. wkr.
Dowell, Hayden	Indust. wkr.	Feathers, Steven L.	Indust. wkr.
Downey, Robert C.	Indust. wkr.	Feldmann, Fred	Indust. wkr.
Doyle, Douglas P.	Indust. wkr.	Fenes, William H.	self
Drange, Edison A.	Indust. wkr.	Ferres, Karyl	self
Draper, A.L.	Umatilla Co. Brd of Comm.	Fife, William T.	Indust. wkr.
Dressel, John W.	Indust. wkr.	Fischer, Joseph L.	Indust. wkr.
Drew, Clayton	Indust. wkr.	Fisher, Gary P.	Indust. wkr.
Druliner, Larry	Indust. wkr.	Fisher, Richard	Indust. wkr.
Duarte, Dennis	Indust. wkr.	Fitzgerald, A. J. (Mrs.)	self
Duarte, Kelley D.	self	Fitzgerald, Melvin B.	Indust. wkr.
Dunham, Maude S.	self	Flammang, Kenneth A.	Indust. wkr.
Dunn, Alan E.	Indust. wkr.	Flathead Irrigation Project	self
Dunn, Donald F.	self	Fleetwood, Patrick H.	Indust. wkr.
Dunn, James L.	Indust. wkr.	Fletcher, Donel J.	self
Dunn, John	self	Fletcher, Robert (Mrs.)	self
Dunn, Richard A.	Indust. wkr.	Fletcher, Zelma	self
Dunn, Violet J.	self	Flick, Aknnette S.	self
Dunn, Vivian	self	Fogelstrom, Elsie	self
Dweak, Janice	Indust. wkr.	Fogelstrom, Gene C.	Indust. wkr.
Dyck, Leo	self	Foley, Thomas S.	U.S. Representative
Dyke, Daniel F.	self	Fonseca, Hector	Indust. wkr.
Eacret, John J. Jr.	Indust. wkr.	Foote, Gordon	self
Eakler, George C.	Indust. wkr.	Foote, Tony	self
East, Virginia R.	Indust. wkr.	Forbis, Robert L.	Indust. wkr.
Eastlick, Kathy	self	Forgett, M. E.	Indust. wkr.
Eastman, Patrick	Indust. wkr.	Forister, William	Indust. wkr.
Eastman, William L.	Indust. wkr.	Foss, Larry	Indust. wkr.
Ecalbarger, JoAnne	Indust. wkr.	Foster, Evelyn M.	Indust. wkr.
Eccarius, Bernard C.	Indust. wkr.	Foster, Harold	Indust. wkr.
Eden, George H.	Indust. wkr.	Foster, J. W.	Indust. wkr.
Edgel, Glenn F.	self	Foster, LeRoy L. (Mrs.)	self
Edin, Berry C.	Indust. wkr.	Foster, Ray Jr.	self
Edmo, Doris	self	Foulke, H. L.	Indust. wkr.
Edmondson, Terry	self	Fox, P. J. (2 letters)	self
Edquist, Stacy S.	Indust. wkr.	Fox, P. J. (Mrs.) (5 letters)	self
Edwards, Cliff M.	self	Fox, Patrick J.	self
Edwards, Reginald	Indust. wkr.	Frakes, James D.	self
Egbert, Myron	self	Frazee, Mark A.	Southern Calif. Edison
Egbert, Robert A.	Indust. wkr.	Fredrickson, Robert	self
Eggert, Charles	Indust. wkr.	Freeman, Charles L.	Indust. wkr.
Eisen, Vincent A.	Indust. wkr.	Freer, Howard R. (Mrs.)	self
Elgis, Keon J.	self	Freer, Richard	self
Ellis, Keith M.	Wash. Dept. of Agriculture	Freer, Richard (Mrs.)	self
Ellertson, David, R.	Indust. wkr.	Freese, Virginia M.	self
Ellthorpe, Steve	self	Freeze, Jon F.	self
Elwood, Lee (Mrs.)	self	French, Ray T.	self

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Froebe, Steven M.	self	Green, Larry B.	self
Froehlich, Fred	self	Greenside, Robert	self
Froehlich, Gail	self	Gregory, Jan	self
Froehlich, Jeff	self	Gregory, Regina	self
Froehlich, Michael	self	Gregory, Roger	self
Fry, Donald L.	Indust. wkr.	Greiner, R. H.	self
Fry, Judy	self	Grey, Christine D. (11 letters)	self
Fryan, Cindy	Indust. wkr.	Grey, Eugene	self
Fulk, Pattie	self	Griffin G.	self
Fuller, John N.	Indust. wkr.	Grigg, Burl H.	self
Fulton, Glenda	self	Grimes, Delbert H.	Indust. wkr.
Furin, Joseph N. Jr.	Indust. wkr.	Grimes, Delbert L.	Indust. wkr.
Gale, David T.	Indust. wkr.	Groshong, Teresa	self
Gallagher, Diana	self	Grossmiller, Patty	self
Gallanger, Jerry	Indust. wkr.	Gudbranson, Jeff C.	Indust. wkr.
Gallinatti, Alfred G.	self	Gudbranson, Wayne A.	Indust. wkr.
Gammon, Russell	Irrigator	Guericke, Lyle & Lottie	Indust. wkr.
Gangwish, John	self	Gurkel, Dan	self
Ganson, Gregg	self	Gustafson, Keith R.	Indust. wkr.
Ganson, Sharon Ann	self	Guth, James	Indust. wkr.
Garcia, Andrew P.	Indust. wkr.	Gutierrez, Jose R.	Indust. wkr.
Garcia, Juan S.	Indust. wkr.	Guzmau, Tom R.	Indust. wkr.
Garcotta, Mary Frances	self	Hackathorn, Ann	Indust. wkr.
Garman, Edward P.	Indust. wkr.	Hackathorn, Dale	Indust. wkr.
Garner, Dave	self	Haddock, Michael H.	Indust. wkr.
Garrison, J. D.	Indust. wkr.	Hadeen, Donald C.	Indust. wkr.
Garza, Ernie	Indust. wkr.	Hagerud, J. E.	self
Garza. Santos Jr.	Indust. wkr.	Hahn, Edgar, Jr.	self
Gasho, Gordon R.	Indust. wkr.	Hahn, Stephen	self
Gast, Stephen L. (Mrs.)	self	Haight, Lawrence	Indust. wkr.
Gearhart, Mary	self	Haines, Jan	self
Gearhart, Merle L.	self	Hale, Chelsey A.	Indust. wkr.
Gegenhuber, Joseph P	Indust. wkr.	Hale, Hamley	Irrigator
Geisler, Carleton E.	Indust. wkr.	Hall, David	self
Geleynse, Dale R.	Indust. wkr.	Hall, Richard W.	Indust. wkr.
Gentry, George B.	Indust. wkr.	Hall, Vernie M.	Indust. wkr.
Gerard, L. R.	self	Hamana, Jack	Irrigator
Gerard, L. R. (Mrs.)	self	Hamilton, Ed (Mrs.)	self
Gerhardus, Raymond L.	Indust. wkr.	Hamilton, Steve	Indust. wkr.
German, Richard B.	Irrigator	Hannifan, Jean	self
Getsinger, Chess	self	Hansen, W. F.	self
Getty, John	self	Harder, Jan	self
Giarde, John P. Jr.	Indust. wkr.	Harding, Goodwin & Katherine	self
Gibbons, Merle R.	Irrigator	Hardy, Walter	Indust. wkr.
Gienger, Loren D.	Indust. wkr.	Harmon, Bill D.	Indust. wkr.
Gilbert, LeAnn	self	Harmon, Dannie L.	Indust. wkr.
Gillette, Chris	self	Harmon, Pete	Indust. wkr.
Gilliland, Jim H.	self	Harmon, Roy L.	Indust. wkr.
Gish, Duane E.	Indust. wkr.	Harmon, Stanley H.	self
Glant, Doug	self	Harms, Kenneth C.	Indust. wkr.
Glant, Douglas F.	self	Harn, Gary	Indust. wkr.
Glant, Douglas F.	self	Harrington, Michael J. Jr.	Indust. wkr.
Glant, Douglas F.	self	Harris, James E.	self
Glover, Clifton	DSI	Harshberger, C. E. (Mr. & Mrs.)	self
Godier, Robert & Jean	self	Harshberger, Willard C.	Indust. wkr.
Godwin, John	self	Hart, Ray M.	self
Goenen, James E.	Indust. wkr.	Harth, Gaye (Mrs.)	Indust. wkr.
Goldade, Ron	Indust. wkr.	Harth, W. B.	Indust. wkr.
Goodner, Nancy	self	Hartley, David	Indust. wkr.
Gordon, L. W.	self	Hartley, Rick	Indust. wkr.
Gordon, Louise J. (with petition)	self	Harvey, Allen R.	Indust. wkr.
Gosson, Mike	self	Harvey, David K.	Indust. wkr.
Gould, Nick	Indust. wkr.	Harvey, Jim	Indust. wkr.
Grady, Robert R.	Indust. wkr.	Harvey, Laddie D.	Indust. wkr.
Gragg, William W.	Indust. wkr.	Harvey, Mark D.	Indust. wkr.
Gram, Scott G.	self	Haskins, Roy W.	Indust. wkr.
Grassmiller, Mike	self	Hatfield, Mark O. (2 letters)	U. S. Senator
Grassmiller, Patty	Indust. wkr.	Hatman, S. R.	Indust. wkr.
Gray, Janet	self	Hattenhauer, Marylee	self
Gray, John	Indust. wkr.	Hauge, Diane	self
Gray, Mary A. (3 letters)	self	Hauge, Don	Indust. wkr.
Gray, Terri (3 letters)	self	Haugen, Bonard G.	Indust. wkr.
Gray, Weslie L.	self	Haugen, Pattie	self
Green, David G.	Indust. wkr.	Hawke, Kenneth M. & Betty L.	self
Green, Glen E.	Indust. wkr.	Hawkins, Dick	Indust. wkr.
Green, Jeffrey S.	Indust. wkr.	Hawley, Vic	Indust. wkr.

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Hay, Douglas J.	Indust. wkr.	Hopper, David	self
Hayden, H. Wayne	Indust. wkr.	Hopper, Marlyn	self
Hayes (Mrs.)	self	Horgen, Art	Indust. wkr.
Hayes, Clarence & Dorothy	self	Hornbeck, Gary M.	self
Hayes, David R.	Indust. wkr.	Hoskbergen, Dale	Indust. wkr.
Hayes, Gil	self	Houg, Arnold G.	Indust. wkr.
Hayes, Steve W.	Indust. wkr.	House, Andrew B.	self
Haymaker, Alton	self	House, Ernest L.	self
Haynes, James D.	Indust. wkr.	Houston, Colleen	self
Hays, Roger P.	Indust. wkr.	Hovda, Shirley Ann	Indust. wkr.
Haywood, R. E	Indust. wkr..	Howard, Margaret	self
Healy, Jerry M.	Col. Basin Elec. Coop, Inc.	Howard, Richard	Indust. wkr.
Hearron, Phillip E. (2 letters)	self	Howard, Robin	self
Heart Broken	self	Howard, William A.	Indust. wkr.
Heaton, David G.	Indust. wkr.	Howe, A. Edward	self
Hedwall, Larry F.	Indust. wkr.	Howe, C. T.	Indust. wkr.
Helber, Wayne	self	Hoyer, Robert J.	Indust. wkr.
Heiselman, Eugene R.	Indust. wkr.	Hubbard, L. E. (Mrs.)	self
Helser, Mike	self	Hubbert, William G. Jr.	self
Heiss, Steven	Indust. wkr.	Hucke, Michael K.	Indust. wkr.
Heist, R. L.	self	Hudson, Charlie D.	Indust. wkr.
*Helgeson, H. L.	Flathead Elect. Coop. Inc.	Hufferd, Donald O.	Indust. wkr.
Helkey, George	self	Hughes, Bernice	self
Helmer, Anne	self	Hughes, John E.	Indust. wkr.
Helvie, Leon	self	Hughes, L. L.	self
Henderson, Daniel V.	Indust. wkr.	Huhn, Walter P.	self
Henkle, Donna B.	self	Hulbert, W.G. Jr. (2 letters)	Snohomish Co. PUD #1
Henning, D. E. (Mr. & Mrs.)	Indust. wkr.	Hulen, R. D.	self
Henry, Claude S.	Indust. wkr.	Hull, Fred J.	Indust. wkr.
Henslee, Karen	self	Hult, Arnold (3 letters)	self
Hensley, Donna L.	self	Hult, Eldon	self
Hensley, Jerry	self	Hult, Karl	self
Herbert, E. M. (Mrs.)	self	Hult, Kelly	self
Hert, Arthur	Indust. wkr.	Hult, Linda	self
Hert, Delores	self	Hult, Marci	self
Hess H. E.	Irrigator	Hult, Pamela	self
Hester, Ruby	self	Hult, Renee	self
Hetland, Gregory	Indust. wkr.	Humphrey, O. J.	self
Hewitt, William C.	Indust. wkr.	Humphreys, Terry	self
Hewrnandez, Frank A.	Indust. wkr.	Hundley, Beverly	self
Hickman, A. L.	self	Hunt, Gordon V.	self
Hicks, J. S.	self	Hunter, Lee	Indust. wkr.
Hicks, R. W.	self	Hunter, Raymond N.	Indust. wkr.
Hidle, Leslie Collins,	self	Huntley, Alfred J.	Indust. wkr.
Hieber, Wayne	self	Huntworth, G. S.	self
Higgins, Gordon R.	self	Hurn, Ruth L.	Indust. wkr.
Hill, Donald R.	City of Burley	Hurt, Frank C. Jr.	Indust. wkr.
Hill, Greg	Wash. State Energy Office	Huser, Robert A.	self
Hill, Phillip S.	self	Hutchinson, Cathy	self
Hill, Ray	Wash. State Grange	Hutton, Sally	self
Hill, Vernon R.	Indust. wkr.	Huxel, Valerie	self
Hill, Warren A. Jr.	Indust. wkr.	Huxtablr, Ronald E.	Indust. wkr.
Hilton, John E.	self	Hymas, Bert & Betty	self
Hindman, Glenn E.	Indust. wkr.	Iassa, Lane M.	self
Hinshaw, Joe	Indust. wkr.	Ilvanakis, Gus	Indust. wkr.
Hoag, R. E.	Indust. wkr.	Ilvanakis, Savvas G.	Indust. wkr.
Hobbs, Jerry D.	Indust. wkr.	Impagliazzo, Antonio	Indust. wkr.
Hobbs, Pat	Indust. wkr.	Ingersoll, Casey S.	Indust. wkr.
Hoctor, Dennis E.	self	Irwin, William A. Jr.	Indust. wkr.
Hoctor, Paul (Family)	self	Isenhart, Larry R.	Indust. wkr.
Hodges, Bryan	self	Jackson, C. Larry	Indust. wkr.
Hodson, Harold J., Lorene & Lylah	self	Jackson, Chuck L.	Indust. wkr.
		Jackson, Darlene	self
Hoekema, Gaylor D.	Indust. wkr.	Jackson, Henry M.	U. S. Senator
Hoekema, Pierson	Indust. wkr.	Jackson, Kenneth T.	Indust. wkr.
Hoffman, Gerald J.	self	Jackson, Lois	self
Hogue, Barbara J.	self	Jackson, Loren B.	Indust. wkr.
Holbrock, Donald C.	self	Jackstadt, Bob	Indust. wkr.
Holeman, Maynard W.	Indust. wkr.	Jacobs, Martin (3 letters)	self
Holeman, Ted L.	Indust. wkr.	Jacobson, Cheryl	self
Holland, Lloyd	Indust. wkr.	Jacobson, Robert J.	Indust. wkr.
Holland, Lloyd L.	Indust. wkr.	Jacoby, Alex	self
Holmann, Heinz	Indust. wkr.	Janes, Mary	self
Holt, Ben E.	Indust. wkr.	Jansen, Cecil J.	Indust. wkr.
Holt, Bill	Indust. wkr.	Jansen, Richard L.	Indust. wkr.
Holt, Roger	L.A. Dept. of Water & Pwr.	Jantze, Robert F.	self

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Jantzen, Robert A.	U.S. Fish & Wildlife	Kelp, William B.	Indust. wkr.
Jardonsky, Louis	self	Kemp, Phillip R.	self
Jaros, Gary D.	self	Kerr, John R. O.	self
Jefferson, Thomas B.	Indust. wkr.	Ketcham, Mona E.	self
Jeffries, Mary	self	Keys, Arthur M.	Indust. wkr.
Jenkin, Bessie	Indust. wkr.	Keys, Merle	Indust. wkr.
Jenkins, Judy	self	Kimball, Dudley N.	Indust. wkr.
Jensen, Donald R.	Indust. wkr.	Kimber, C. B.	Indust. wkr.
Jensen, Evelyn & Harry A.	self	Kimbley, James D.	Indust. wkr.
Jensen, Richard M.	Indust. wkr.	Kindrick, Gerry	Indust. wkr.
Jerome, Joseph H. & Velma	self	King, Arnold W.	self
Johns, Marie A.	self	King, Brian K.	Indust. wkr.
Johnsen, Julie B.	self	King, Harvey A.	Indust. wkr.
Johnsen, Richard S.	Indust. wkr.	King, LaVerne W.	Indust. wkr.
Johnson, Charles, R.	Indust. wkr.	King, Robert J.	Indust. wkr.
Johnson, Donald W.	self	King, Vance J.	Indust. wkr.
Johnson, Gust R.	Indust. wkr.	Kinler, Margaret	Indust. wkr.
Johnson, James E.	self	Kinman, Kenneth C.	Indust. wkr.
Johnson, James E.	Indust. wkr.	Kinter, Larry E.	Indust. wkr.
Johnson, James M.	Indust. wkr.	Kirk, James A.	Indust. wkr.
Johnson, Jane & Kelly	self	Klineman, Paul	Indust. wkr.
Johnson, John A.	self	Knapp, Theron	Irrigator
Johnson, John A.	Indust. wkr.	Knutson, Lowell D.	Indust. wkr.
Johnson, John L.	self	Koehl, (Mr. & Mrs.)	self
Johnson, Kenneth R.	self	Koker, Robert L.	Indust. wkr.
*Johnson, Leayesh	PNW Generating Co.	Kolbe, Roger L.	Indust. wkr.
Johnson, Leonard T.	Indust. wkr.	Kolsen, Larry	self
Johnson, Mary (Mrs.)	self	Koop, William H. Jr.	Indust. wkr.
Johnson, Peter A.	self	Kordon, George	self
Johnson, Phillip S.	Indust. wkr.	Kortge, K. C.	self
Johnson, Raymond H., Wilma E., Donald	self	Kortlever, Glen M.	Indust. wkr.
		Kovacevoc, Tony A.	Indust. wkr.
Johnson, Reva	self	Krahmer, Calvin	self
Johnson, Richard	self	Krenelka, Blaine	self
Johnson, Steven J.	Indust. wkr.	Krueger, Greg	self
Johnson, Thomas E.	Indust. wkr.	Krummenacker, Toni	self
Johnson, Tom O.	self	Kubler, Elaine V.	self
Johnson, Tracy	Indust. wkr.	Kubler, Howard E.	self
Johnston, John L.	Indust. wkr.	Kuhns, Frederick	self
Jones Jr., Vic	Indust. wkr.	Kuller, Jenne	self
Jones, David	self	Kuoppala, Mathew	Indust. wkr.
Jones, Fred	Irrigator	Kuppenbender, Gary L.	self
Jones, Frederick N.	Indust. wkr.	Kurtz, Thelma L.	self
Jones, Irene A.	self	Kusky, Joe	self
Jones, Patricia	self	Kyllingmark, Kevin O.	Indust. wkr.
Jones, Raymond E.	Indust. wkr.	LaBounty, Clifford F.	Indust. wkr.
Jones, Robert H.	Indust. wkr.	LaBounty, John R.	Indust. wkr.
Jones, Robert L.	Irrigator	LaFave, Robin W.	Indust. wkr.
Jones, Sandra	self	LaFollette, Bob & Family	Indust. wkr.
Jones, Steven	Indust. wkr.	LaMarsh, Dick	self
Jones, Thomas, C.	self	LaRose, Michael E.	Indust. wkr.
Jonillonis, Diane	Indust. wkr.	Lacefield, Leon	self
Joplin, Clarence D.	Indust. wkr.	Lacock, David	Indust. wkr.
Jordan, Jeanie	self	Lacy, Dan	Indust. wkr.
Jungers, James L.	self	Lacy, Dennis	Indust. wkr.
Justin, Mayor Jim	City of Vancouver	Lafrenz, A. W.	self
Kalmbach, Gary L.	self	Lagerwey, Nick	Indust. wkr.
Kalmback, Cecile M.	self	Lake, Raye	self
Kammerzell, John H.	Indust. wkr.	Lamarsh, Dick	Indust. wkr.
Kangas, Wes	self	Lamb, Frank G.	Irrigator
Kaps, Lonnie M.	self	Lamb, Lee	self
Kartz, Leonard H.	Indust. wkr.	Lambertus, Keith	self
Kasischle, Alan	self	Landtister, Francis L.	Indust. wkr.
Katcho, Nabil	Indust. wkr.	Lane, A. (Mrs.)	self
Keating, J. P.	Indust. wkr.	Lane, Addison	Indust. wkr.
Keep, Elva	self	Lane, Greg	Indust. wkr.
Keep, Vern	self	Lane, Larry	Indust. wkr.
Kellman, Leo A.	self	Lane, Patty	self
Kelm, Gregory B.	Indust. wkr.	Lang, Marvin	Indust. wkr.
Kelzus, Danell	self	Langer, Robert R.	Indust. wkr.
Kell, Roger	Indust. wkr.	Lankhaar, Percy W.	Indust. wkr.
Kellar, Floyd J. (Mr. & Mrs.)	self	Larsen, Eugene L.	Indust. wkr.
Kellogg, Benny	self	Larson, Derril (2 letters)	self
Kellogg, George	self	Larson, Hannah M.	self
Kelly, Glen E.	self	Larson, James S.	Indust. wkr.
Kelner, W. P.	self	Larson, Kenneth C. (2 letters)	self

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APPENDIX C

Individual	Representing
Latimer, Tom	self
Lattig, Larry K.	Indust. wkr.
Lautenback, Evelyn	self
Lawrence, Alvin L.	Indust. wkr.
Lawrence, Melvin	Irrigator
Lawrence, Russ	self
Lawrence, Stephen	self
Lawrence, Steve	self
Lawson, Roger D.	Indust. wkr.
Lawyer, Richard J.	Indust. wkr.
LeBreton, Jack M.	self
LeDesma, John M.	Indust. wkr.
LeValley, James H.	self
Leary, C. Nick	Indust. wkr.
Ledbetter, Keith L. (with Petitions)	self
Lee, Allen	Oregon State Dept. of Agriculture
Lee, Bill (Mr. & Mrs.)	self
Lee, Elsie M.	Indust. wkr.
Lee, Jal H.	Indust. wkr.
Leer, Gary W.	Indust. wkr.
Leff, Helen	self
Leff, Joy A.	Indust. wkr.
Leigang, Dan	Indust. wkr.
Leininger, John D.	Indust. wkr.
Leino, E. (Mrs.)	self
Leinweber, Alvene	self
Lenox, Stanley (Mr. & Mrs.)	self
Lenzi, Michelle	self
Leonard, Deryl	self
Leonard, Harold J.	Indust. wkr.
Lepinski, Tom	Indust. wkr.
Lepley, Richard E.	Indust. wkr.
Leppala, James K.	Indust. wkr.
Lester, Hazel	self
Lester, James I.	self
Leuenberger, Arnold L.	Indust. wkr.
Leuenberger, Lyle V.	Indust. wkr.
LeValley, James H.	Indust. wkr.
Levell, Donald K.	Indust. wkr.
Lewis & Clark Ranch - Mackay	self
Lewis, Dorothy J.	self
Lewis, Frank E.	Indust. wkr.
Lewis, John	self
Lewis, Robert L.	Indust. wkr.
Lilja, Zeba	self
Lind, Carl F.	Indust. wkr.
Lindenberg, Howard	self
Lindhorst, L. H.	self
Ling, John	self
Linker, Bessie	Indust. wkr.
Linker, Tanya	self
Linsdey, Bob	Indust. wkr.
Linton, Fred M.	Indust. wkr.
Linton, Viola	self
Listenbarger, Earl R.	Indust. wkr.
Littleton, Lloyd M.	Indust. wkr.
Lively, John D.	self
Locker, Pat A.	Indust. wkr.
Lockert, L. E.	self
Loeber, Edgar & Myrta	Irrigator
Loeber, Loren & Lucy	Irrigator
Lofland, Mead M.	self
Loften, Bob & Ruth	self
Logan, David	Indust. wkr.
Lonewell, Caprice (Mrs.)	self
Loney, Arlin J.	Indust. wkr.
Long, Morris N.	Indust. wkr.
Longfellow, J. J.	Indust. wkr.
Longfellow, Patricia R.	self
Looker, Derek A.	Indust. wkr.
Loomer, Kenneth	Indust. wkr.
Loomis, Larry J.	Indust. wkr.
Lorenz, B. A.	Indust. wkr.
Loudd, Patricia	self

Individual	Representing
Love, Donald	self
Lovewell, Dewey,	self
Low, James R.	Indust. wkr.
Lowe, Leon R.	self
Lowther, Christie	Indust. wkr.
Loya, Joe A. Jr.	Indust. wkr.
Lucey, Mike	self
Lulow, Stanley R.	self
Luna, Marci M.	Indust. wkr.
Lutter, A. M. (Mr. & Mrs.)	self
Luttrell, Winston	Indust. wkr.
Lutye, Danny D.	Indust. wkr.
Lyddon, Carolee M.	self
Lyddon, Phillip D.	Indust. wkr.
Lykins, Edward E.	Indust. wkr.
Lykins, M. E. (Mr. & Mrs.)	self
Lynch, Bradford L.	Indust. wkr.
Maas, Alvin D.	Indust. wkr.
Maas, John	Indust. wkr.
MacKnight, William F.	self
Mack, David A.	self
Mackenzie, L.A. (Mrs.)	self
MacKay, Donald G.	Irrigator
Mackenzie, J.R.	self
Mackey, Donald G.	Irrigator
Maddox, Floyd D.	Indust. wkr.
Maes, (Mr. & Mrs.)	self
Magill, Daryl W.	Indust. wkr.
Magill, Leona M.	self
Mahala, Marshall	Indust. wkr.
Mahon, K. C.	self
Maier, William B.	self
Main, Susan	self
Maisbary, Dick	Indust. wkr.
Mammenga, Goral	self
Manguart, Charles	Indust. wkr.
Manka, Vernon L.	Indust. wkr.
Mann, Del A.	Indust. wkr.
Mann, Ronald E.	Indust. wkr.
Manthey, James E.	Indust. wkr.
March, Kenneth L.	Indust. wkr.
Margis, John D.	Indust. wkr.
Markham, Bill	Oregon Representative
Marshall, Gale	self
Marshall, Paul	Indust. wkr.
Martilla, John A.	self
Martin, Gary L.	Indust. wkr.
Martinez, Andrew A.	self
Martinez, Eliseo S.	Indust. wkr.
Martinez, Isable	Indust. wkr.
Mathews, Mark V.	Indust. wkr.
Mathieus, George	self
Mattly, LeRoy & Lorena	Irrigator
Matz, Jeff (Mr. & Mrs.)	Indust. wkr.
Mayfield, Frances Sue	Indust. wkr.
Mayfield, Larry L.	Indust. wkr.
Mays, Velma	self
McAfee, LeVerne A.	Indust. wkr.
McAllister, Beverly (3 letters)	self
McAllister, Earl (3 letters)	Indust. wkr.
McAllister, Lucy	self
McAllister, Marion (Mrs.)	self
McAllister, Ted E.	Indust. wkr.
McCall, James D.	Indust. wkr.
McCammack, Jack	Indust. wkr.
McCauley, Donald R.	Indust. wkr.
McClellan, Jack	Indust. wkr.
McCluskey, Russell C.	Indust. wkr.
McConnell, Delbert (Mr. & Mrs.)	self
McCormick, John L. Jr.	Indust. wkr.
McCoy, J. J.	self
McCoy, Lester B.	Indust. wkr.
McCoy, Lynnette	self
McCracken, Robert	self
McDonald, Norman	Indust. wkr.
McFann, Greg	self

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Individual	Representing	Individual	Representing
McGee, William R.	Indust. wkr.	Moore, Linda	self
McGregor, Gary (Mr. & Mrs.)	self	Moore, Michael E.	self
McHale, Ronald E.	self	Moore, Thomas R.	Indust. wkr.
McHale, Sonja D.	self	Morales, Salvador	self
McJunkin, Daisy	self	Moran, Walter	Indust. wkr.
McJunkin, Jennifer	self	Morford, Wallace	self
McJunkin, Kathy	self	Morgan, Bruce	Indust. wkr.
McJunkin, Shirley D.	self	Morgan, David A.	Indust. wkr.
McJunkin, Stewart	Indust. wkr.	Morgan, David D.	Indust. wkr.
*McKenzie, Kirk	Pacific Gas & Elec. Co.	Morgan, Jayne M.	self
McKinney, Don	self	Morgan, Kenneth G.	Indust. wkr.
McLead, Robert	Indust. wkr.	Morgan, Mark	self
McLellan, Larry	self	Morgan, Roy W.	Indust. wkr.
McLeurin, Leigh	self	Morgan, S. E.	self
McMurren, DAve	Indust. wkr.	Morin, Seberino T. Jr.	Indust. wkr.
McNielly, John J.	self	Morris Jr., Clifton R.	self
McPherson, Glen	Indust. wkr.	Morris, Ray	Indust. wkr.
Meadows, Mike	Indust. wkr.	Morris, Ronald P.	Indust. wkr.
Medlin, J. D.	self	Morris, Thomas R.	self
Medlin, J. D.	self	Morrison, Roy & Pat	self
Mehigan, Patrick J.	Indust. wkr.	Morroco, Richard	self
Mehlenbacher, Alan	Irrigator	Mullen, Barbara	self
Mehlenbacher, Quentin	Irrigator	Munez, John	self
Merritt, Claudia & Fred	self	Munson, Cliff	self
Mesecher, Dennis G.	self	Munson, Douglas A.	Indust. wkr.
Mesecher, Randalle (Mrs.)	self	Munson, Eugene	self
Metcalfe, Forest E.	Indust. wkr.	Murry, Rodney D. (Mrs.)	self
Meteger, Gerald D.	Indust. wkr.	Nagle, Barbara	self
Metzger, Randy D.	Indust. wkr.	Nagle, Bill	self
Meyer, Gary E.	Indust. wkr.	Nall, Dolpha J.	self
Meyer, Jerold L.	self	Nash, Eldon	self
Meyer, Jerold L.	Indust. wkr.	Nason, Harold	Indust. wkr.
Meyer, John	self	Navarre, Jack G.	self
Michnick, Diane K.	self	Nazelrod, Gene	self
Middleton, Arthur H.	Indust. wkr.	Neely, John C., Jr.	self
Miles, Randel L.	Indust. wkr.	Neller, Lorreta	self
Miller, Bert	Indust. wkr.	Nelson, Bennie	self
Miller, Charles D.	self	Nelson, D. A.	self
Miller, Debbie J.	Indust. wkr.	Nelson, Evans G.	self
Miller, Dwight E.	self	Nelson, Heather E.	self
Miller, Faye	self	Nelson, Howard J. & Lila	self
Miller, Harold L.	Indust. wkr.	Nelson, Milton R.	self
Miller, Janet	Indust. wkr.	Neubauer, LeRoy	Indust. wkr.
Miller, Karen J.	self	Neubauer, Michael H.	Indust. wkr.
Miller, Paul	Indust. wkr.	*Neukom, Jean S.	Midway Elec. Coop
Miller, Percy J.	self	Neuneker, Andy	self
Miller, Randy L.	Indust. wkr.	Neuneker, R. L. Jr.	Indust. wkr.
Miller, Richard (Mr. & Mrs.)	self	Nevins, Michael E.	Indust. wkr.
Miller, Robert	self	Nevo, Maurice	self
Miller, Robert L.	Indust. wkr.	Newcomb, Wayne	Irrigator
Miller, William H.	Indust. wkr.	Newell Jr., Richard M.	self
Miller, William M.	Indust. wkr.	Newell, Mary Ann	self
Millon, Dennis W.	Indust. wkr.	Newell, Roger D.	Indust. wkr.
Mills, Joseph P.	Indust. wkr.	Newton, Samuel	self
Miner, Gerald	Indust. wkr.	Nicholson, William R.	Indust. wkr.
Miner, Lucille	self	Nielsen, Hoagie	self
Minkler, K. V.	Indust. wkr.	Nielson, Douglas L.	Indust. wkr.
Minor, Patricia A.	self	Niemela, Carl S.	Indust. wkr.
Minor, Richard A.	self	Niemela, Michael Harvey	self
Mitchell, Curt	self	Nims, Gene	Indust. wkr.
Mittleider, Dawn	self	Noble, Roy	Indust. wkr.
Moberly, Sidney D.	self	Nolan, Gerald H.	Indust. wkr.
Mobley, Jack E.	Indust. wkr.	Nolan, Merril D.	Indust. wkr.
Mobley, Keith A.	self	Nolen, L. M.	self
Mock, Maurice L.	Indust. wkr.	Nordby, Allan	Indust. wkr.
Moena, Howard C.	Indust. wkr.	Nordby, Gordon M.	Indust. wkr.
Mollahan, Paula J.	Indust. wkr.	Nordby, Lucas E.	Indust. wkr.
Monaghan, Richard A.	Indust. wkr.	Nordskog, Kenneth & Shirley	Indust. wkr.
Monette, Marleta	self	Northrup, Norman	self
Monette, Rolland A.	Indust. wkr.	Noyes, Gordon L. (3 letters)	self
Monger, John	Indust. wkr.	Nugent, Gordon (Mrs.)	self
Monroe, A. L.	self	O'Brien, Aris	Indust. wkr.
Monroe, Rocky D.	Indust. wkr.	O'Brien, Kenneth L.	Indust. wkr.
Montgomery, Marcelle S.	self	O'Connell, Michael	self
Montoya, Joe	Indust. wkr.	O'Gorman, Michael J.	Indust. wkr.
Moore, Kenneth L.	Indust. wkr.	O'Rourke, L.S.	self

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Individual	Representing
Oaks, Annadale	Indust. wkr.
Oaks, Thomas R.	Indust. wkr.
Odell, Bill	Indust. wkr.
Odell, Russ C.	Indust. wkr.
Ohlswager, M. D.	self
Olason, Dennis L.	Indust. wkr.
Olds, Robin E.	self
Olinger, John C.	Indust. wkr.
Olsen, Gary J.	Indust. wkr.
Olsen, Gordon S.	self
Olsen, Richard R.	self
Olson, Brian F.	Indust. wkr.
Olson, Debbie	self
Olson, Patricia K.	self
Olson, Rich (Mrs.)	self
Opp, Alan W.	self
Orchard, Richard E.	Indust. wkr.
Ordos, Chris W.	Indust. wkr.
Ordway, Roy	Indust. wkr.
Oritz, Angel L.	Indust. wkr.
Orloff, Norman A.	Indust. wkr.
Ortega, Cheryl B.	self
Ortega, Juan	Indust. wkr.
Orthmeyer, John	self
Ortiz, Zacarias F.	self
Orton, Charles W.	Indust. wkr.
Osborne, Jack	Indust. wkr.
Osborne, John Jr.	Indust. wkr.
Osburn, Otis O.	Indust. wkr.
Oswaer, Harvey (Mrs.)	self
Otto, Glen E. (2 letters)	Oregon Representative
Owen, Bob	self
Owen, David R.	labor organization
Owen, Marilyn	Indust. wkr.
Ownes, J. I.	self
Pace, W. B. Jr.	Irrigator
Packwood, Bob	U.S. Senator
Paegle, Patric	Indust. wkr.
Pake, Linda T.	self
Pake, Neil D.	Indust. wkr.
Paker, Ray	self
Paladie, Frances	self
Paladie, James	self
Palmer, John	Indust. wkr.
Panisko, Peggy	self
Parker, Ernest W.	Indust. wkr.
Parker, Frank E.	Indust. wkr.
Parker, Ray	Indust. wkr.
Parker, Timothy B.	Indust. wkr.
Parker, Whit B.	Indust. wkr.
Parkin, Linda	Indust. wkr.
Parks, J. B.	self
Parks, Larry L.	self
Parks, Linda G.	self
Parks, Robert H.	Indust. wkr.
Parsons, Sudie	Indust. wkr.
Paschal, C. R.	self
Paschal, Sarah	self
Pashone, Charles	self
Patchett, Carrie L.	self
Patterson, Charles	self
Patterson, Larry W.	Indust. wkr.
Paul, Lenly W.	self
Paxton Burt A.	Indust. wkr.
Paxton, Steven W.	Indust. wkr.
Pearce, Courtenay	self
Pearce, Marvin	Indust. wkr.
Pearson, Robert C.	Indust. wkr.
Pederson, Gary L.	Indust. wkr.
Pederson, Rita M.	self
Pekema, Andrew	Indust. wkr.
Pena, Robert	Indust. wkr.
Pendleton, Gerald C.	Indust. wkr.
Pengra, Jack M.	Indust. wkr.
Pennington, J. A.	Indust. wkr.
Perez, Cesar	self
Perez, Greg	Indust. wkr.
Perez, Greg (Mrs.)	self
Perkins, Lyle W.	Indust. wkr.
Perrin, Alex J.	Indust. wkr.
Perry, Darrel	Indust. wkr.
Perry, Dorothy	self
Perry, Max	Indust. wkr.
Peter, Michaell	Indust. wkr.
Petermann, Don E. (2 letters)	self
Petersen, Don & Darlene	self
Petersen, G. H.	self
Peterson, James L.	Indust. wkr.
Peterson, Leslie L.	Indust. wkr.
Pfaff, Wallace G.	Indust. wkr.
Pfannenstiel, Kenneth F.	Indust. wkr.
Pfeiffer, Donald	Indust. wkr.
Phall, James R.	Indust. wkr.
Phair, Sidney	Indust. wkr.
Pham, An Hong	Indust. wkr.
Phipps, Charles A.	self
Phipps, Corene A.	Indust. wkr.
Phipps, Fred	Indust. wkr.
Pierce, Bob & family	Indust. wkr.
Pierce, Glenn	self
Pilon, Gene	Indust. wkr.
Pincock, Brian S. (2 letters)	Indust. wkr.
Pincock, Patricia S.	self
Piper, David E.	PNW Generating Co.
Pipkin, Jim L.	Indust. wkr.
Pittman, David	self
Place, Greg T.	Indust. wkr.
Placid, Ken	Indust. wkr.
Plata, Juan O.	Indust. wkr.
Pluard, LeRoy	Indust. wkr.
Plucker, Michael A.	self
Polca, R. F.	Indust. wkr.
Polinkus, Gordon E.	Indust. wkr.
Pomante, Thomas D.	self
Pompa, Daniel Z.	Indust. wkr.
Pontour, Edith	self
Pontour, Richard	Indust. wkr.
Poole, Blaine L.	self
Porter, Betty A.	self
Porter, Ken	self
Potts, John H.	Indust. wkr.
Pounds, Gaylord (Mrs.)	self
Pounds, Gaylord D.	self
Powell, James R.	Indust. wkr.
Powell, Morris	Indust. wkr.
Powell, Stephan P.	Indust. wkr.
Presta, Dolores	self
Prink, William E.	Indust. wkr.
Pritchett, LeRoy	Indust. wkr.
Pritchett, Robert D. (Mr. & Mrs.)	self
Proffitt, Randy	Indust. wkr.
Prosser, James	Indust. wkr.
Pruitt, Charles & Maxine McDade, Mabel & Donald	Irrigator
Putham, Craig H.	Indust. wkr.
Quade, Dennis H.	self
Quast, Lila	self
Quayle, Howard J.	Indust. wkr.
Raffo, Karl I.	Indust. wkr.
Ralph, William M.	Indust. wkr.
Ramsey, Cecil	Indust. wkr.
Ramsey, J. A.	self
*Ramseyer, James P.	Blachly-Lane Cty Coop.
Ranslam, Don	self
Rash, B. J.	self
Rasmussen, Robert A.	self
Ratcliff, Carl F.	Indust. wkr.
Rathbone, Donna	self
Rathbone, Terry J.	Indust. wkr.
Rathburn, Monty W.	Irrigator
Ratliff, Kenneth	Indust. wkr.
Rautio, Frances Noyes (Mrs.)	self

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APPENDIX C

Individual	Representing	Individual	Representing
Ray, Ken	self	Roshone, C. (Mrs.)	self
Rayborn, Larry	Indust. wkr.	Rosler, Gordon W.	Fair Use Snohomish Energy
Raynor, Harry R., Sr.	Indust. wkr.	Roth, Benjamen L.	Indust. wkr.
Reed, Alan D	Indust. wkr.	Roundy, Ruth	self
Reed, Darcie	self	Roushe, E.	Indust. wkr.
Reed, Keith R.	Indust. wkr.	Rowe, Cindy	self
Reed, Norwell & Kathy Taylor	Indust. wkr.	Rowe, Gary D.	self
Reed, Pamela	Indust. wkr.	Rowe, Janet	self
Reed, Stephen J.	Indust. wkr.	Roy, Margaret	self
Reel, Coy	self	Ruark, David & Nancy	Indust. wkr.
Reeves, Joseph A.	Indust. wkr.	Ruccick, William J.	Indust. wkr.
Rehberger, Larry M.	Indust. wkr.	Rudig, Stanley, W.	Indust. wkr.
Reichel, Rodney R.	Indust. wkr.	Ruff, Steven	self
Reimer, John H.	Indust. wkr.	Ruff, Steven R.	Indust. wkr.
Relaford, Steve	Indust. wkr.	Ruff, Steven R. (family)	self
Remington, Lee	Indust. wkr.	Ruiz, Tony	Indust. wkr.
Reutzel, M. E.	Indust. wkr.	Rush, Paul (Mr. & Mrs)	self
Revere, Randall	Indust. wkr.	Russell, Dan R.	self
Rexhausen, Roy C.	Indust. wkr.	Russell, Frances E.	Indust. wkr.
Reynolds, James O.	Indust. wkr.	Ryan, Gary J.	Indust. wkr.
Rice, Charles R.	self	Saab, Al	Indust. wkr.
Rice, Michael O.	Indust. wkr.	Sadler, Genevlena	self
Rich, James	self	Sager, John L.	Indust. wkr.
Richard, Carolyn	Indust. wkr.	Saldivar, Eugene	self
Richard, Ray	Indust. wkr.	Salhus, Lowell B.	Indust. wkr.
Richardson, Mike & Marilyn	self	Saling, George (Mr. & Mrs.)	self
Richardson, Roscoe	Indust. wkr.	Salme, Wallace	self
Richardson, Thomas G.	Indust. wkr.	Salter, William M.	Indust. wkr.
Richman, M. (Mrs.)	self	Sampson, Ray	Indust. wkr.
Richman, Shorn	self	Samuelsen, Roald	self
Rickman, Harley & Jean	self	Sandaval, Jess	Indust. wkr.
Rideout, John C.	Indust. wkr.	Sanders, Francis (Mr. & Mrs.)	Irrigator
Riegger, Irene	self	Sanders, Patrick W.	Indust. wkr.
Ries, Kenneth E.	self	Sandifer, Terry	Indust. wkr.
Rigg, Deserie	self	Sandlin, Sue A.	Indust. wkr.
Rigg, Jim	self	Sandstrom, Frank E.	Indust. wkr.
Rigg, Mary	self	Sapp, Bill	self
Rigg, Thomas T.	Indust. wkr.	Sargeant, Kay	self
Rigg, Tom	Indust. wkr.	Sargeant, R. T.	Indust. wkr.
Rinta, Carolyn	Irrigator	Sasken, John J.	Indust. wkr.
Rinta, John R. (Dick)	self	Sauceda, Raul	Indust. wkr.
Rishworth, J. C.	Indust. wkr.	Savage, Debbie L.	self
Rishworth, Patty Jo	self	Savage, Lyle, E.	self
Rising, Amy	self	Savage, Sharon M. (2 letters)	self
Rising, R. C.	self	Sayles, Terry	self
Ritter, Arnold J.	self	Sayles, Terry (Mrs.)	self
Rizzo, Tom (2 letters)	self	Schauer, Hans J.	Indust. wkr.
Robbins, Richard D.	Indust. wkr.	Scheir, Hollis S.	self
Robert, Victor E.	self	Schell, Gregory	Indust. wkr.
Roberts, Gregory W.	Indust. wkr.	Scheuman, Donna M.	self
Roberts, Ray D.	Indust. wkr.	Schlechter, Monte L.	Indust. wkr.
Roberts, Royden	self	Schmitt, David P.	Indust. wkr.
Roberts, Stephanie	self	Schneider, Harvey K.	self
Roberts, T. L.	self	Schneider, William R.	Indust. wkr.
Robertson, Dick	Indust. wkr.	Schnepel Hans R.	Indust. wkr.
Robertson, Fred N.	self	Schnepp, Leslie	Indust. wkr.
Robertson, R. J. (Mr. & Mrs.)	self	Schnepp, Leslie	Indust. wkr.
Robey, Michael	Indust. wkr.	Schon, Dick	Indust. wkr.
Robson, Cindy	self	Schonberger, DeLoss E.	Indust. wkr.
Rockenbach, Collin A.	Indust. wkr.	Schrader, Guy (Mrs.)	self
Rodda, Dan	Indust. wkr.	Schrader, Willis A.	Indust. wkr.
Rodda, James B.	Indust. wkr.	Schuller, Harland (Mrs.)	self
Rodriquez, Arthur	Indust. wkr.	Schultz, Arthur	self
Roedell, Richard R.	Indust. wkr.	Schultz, Herman H.	Irrigator
Rogers, David S.	Indust. wkr.	Schuster, Stan	self
Rogus, Mary	self	Schwinof, Ruth L.	Indust. wkr.
Rohr, Dennis	self	Schwisow, Marcie	self
Rolland (Mrs.)	self	Scott, Howard	Indust. wkr.
Roller, Eugene A.	Indust. wkr.	Scott, Ralph R.	Indust. wkr.
Romig, Mark S.	self	Scroch, David D.	Indust. wkr.
Rood, Gary J.	Indust. wkr.	Seaver, Graham	self
Rooper, David J.	Indust. wkr.	Seelyle, Melvin J.	Indust. wkr.
Rooper, Penny	self	Seifer, Thomas	Indust. wkr.
Roosma, Elmer J.	Indust. wkr.	Seifert, Cheryl A.	self
Roscoe, Steven E.	Indust. wkr.	Sepulveda, Jose	self
Rosenburg, Robert G.	Indust. wkr.	Severson, Carle	Indust. wkr.

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Individual	Representing
Severson, Steve	Indust. wkr.
Seward, Charles W.	Indust. wkr.
Shaffer, Donna	self
Shaffer, Tom (2 letters)	Indust. wkr.
Shah, Pradip J. (Mr. & Mrs.)	Indust. wkr.
Shank, Elsie	self
Sharp, Jim	Indust. wkr.
Shaw, Ann	self
Shaw, Loren D.	Indust. wkr.
Shea, Michael (Mr. & Mrs.)	self
Shearer, Gary	self
Shell, Dennis	Indust. wkr.
Shepard, Dwayne	Indust. wkr.
Shephard, Leah	self
Shepler, R.	self
Shepler, R. (Mrs.)	self
Shetler, Jack E.	Indust. wkr.
Shine, Clarence H.	Indust. wkr.
Shinnich, Doris	Indust. wkr.
Shinnick, Thomas P.	Indust. wkr.
Shirley, Bob (Mrs.)	self
Shirley, Dan & Peggy (2 letters)	self
Shirley, Jeff	self
Shirley, Lon	self
Shirley, Robert K.	Indust. wkr.
Shotlan, Nick	self
Shouse, Mary A.	self
Shrader, Guy A.	self
Shumway, Bob	self
Sidinger, Ron	Indust. wkr.
Sievert, Howard N. (Mr. & Mrs.)	Indust. wkr.
Sigl, Max	Indust. wkr.
Sikes, Odis, Jr.	Indust. wkr.
Sikes, Tina L.	self
Sittars, Lloyd E. (Mrs.)	self
Silva, Julian G.	Indust. wkr.
Silves, Donald A.	Indust. wkr.
Simmons, Gary A.	Indust. wkr.
Simon, Clay R.	self
Sims, David M.	Indust. wkr.
Sipes, Harry	Indust. wkr.
Sipes, Mary Ann	self
Skov, Milton	Northern Wasco Co. PUD
Skroch, Maria B.	self
Slagle, Dale	Indust. wkr.
Slatt, Vincent P.	Inland Power & Light Co.
Sleasman, Dale K.	Indust. wkr.
Slemp, Jack	Indust. wkr.
Small, Bliss R.	Indust. wkr.
Smart, Harold	self
Smith, Bryant L.	Indust. wkr.
Smith, Carlton L.	Indust. wkr.
Smith, Carol	Indust. wkr.
Smith, Chuck	Indust. wkr.
Smith, Cleve	self
Smith, Curtis	self
Smith, Eula	self
Smith, George	Indust. wkr.
Smith, Harold	self
Smith, Les	self
Smith, Leslie	self
Smith, Michelle	Indust. wkr.
Smith, Norwood (Mr. & Mrs)	self
Smith, Roger A.	self
Smith, Sharon	self
Smith, Sidney	self
Smith, Steven	Indust. wkr.
Smith, Steven	self
Smith, Ted J.	self
Smith, Wesley H.	Indust. wkr.
Smits, Eugene A.	Indust. wkr.
Smythe, David E.	self
Snider, Darrell W.	Indust. wkr.
Snider, Edwin L.	Indust. wkr.
Sowers, Ted P. Jr.	Indust. wkr.
Spahr, Robert E.	self

Individual	Representing
Spaulding, Robert	Indust. wkr.
Spees, Ray L.	Indust. wkr.
Spencer, Charles & Winona	self
Spenser, Charles W.	self
Spenser, William E.	Indust. wkr.
Spindle, R. C.	self
St. Pierre, Gary W.	Indust. wkr.
St. Pierre, Michael W.	Indust. wkr.
Stace, Derald & Carol	Indust. wkr.
Stacy, Charles C.	self
Staehnke, David	self
Stalberger, Melvin	self
Stamm, Allen C.	Indust. wkr.
Stark, Dick	self
Starkenburg, Robert J.	Indust. wkr.
Staufer, Joanne	self
Steege, LeRoy	Indust. wkr.
Steele, Jack A.	Indust. wkr.
Stefanski, Joseph (Mrs.)	self
Stefanson, Gary	Indust. wkr.
Stegeman, J. David	self
Steinbach, Ronald J.	Indust. wkr.
Stephens, Norman C.	self
Stevens, Jim	self
Stevens, Reggie, D.	Indust. wkr.
Stevenson, Linda	self
Stewart, H. D.	self
Stewart, Randy	self
Stewart, Robert	Indust. wkr.
Stidman, Scott A.	Indust. wkr.
Stilwater, Robert (Mr. & Mrs.)	self
Stone, Ama Fay	Indust. wkr.
Stone, Clyde D.	self
Stoner, Barry	self
Storall, Brian	Indust. wkr.
Storm, Mark	self
Stout, James T.	Indust. wkr.
Stratton, Don (Mrs.)	self
Stratton, Franklin D.	Indust. wkr.
Strickland, Diane	self
Stroebel, Clinton R.	Indust. wkr.
Stubbs, Parker	Indust. wkr.
Stuteville, Granville R.	Indust. wkr.
Sugg, William A. (Mr. & Mrs.)	self
Suh, Jung W.	Indust. wkr.
Sundstrom, William A.	Indust. wkr.
Sutherland, Michael	Indust. wkr.
Sutphen, I. Hahn	self
Swanaset, George D.	Indust. wkr.
*Swartz, Jack	Prairie Power Coop. Inc.
Swift, Mary	self
Swift, Richard D.	Indust. wkr.
Swoboda, Fred	self
Sytsma, Allen	Indust. wkr.
Sytsma, Ronald J.	Indust. wkr.
Tabor, Gene (Mrs. & Mrs.)	self
Tallman, Ben B.	Indust. wkr.
Taskey, J. R.	Indust. wkr.
Tatro, Barbara	self
Tatro, Lynn	Indust. wkr.
Tatum, Laurie L.	self
Taylor, Glen(Mr. & Mrs.)	self
Taylor, Harold E.	Indust. wkr.
Taylor, Linda A. B.	Indust. wkr.
Taylor, William E.	Indust. wkr.
Teague, Thomas N.	Indust. wkr.
Teas Jr., W. A.	self
Templeton, J. E.	Indust. wkr.
Tenkley, Donald D.	Indust. wkr.
Thackray, Kimberly A.	Indust. wkr.
Thatcher, Lee	Indust. wkr.
Thipado, Charles H.	Indust. wkr.
Thomas, Gay D.	Indust. wkr.
Thomas, Nina	self
Thomas, R. J. (Mrs.)	self
Thomason, Ross T.	Indust. wkr.

* Denotes Commenter who is represented in the rate case as a party; these comments were not included within those of the participants

Individual	Representing
Thompson Jr., Donald E.	self
Thompson, Joe	Indust. wkr.
Thompson, Keith	Indust. wkr.
Thompson, Keith	self
Thompson, Melvin & Delores	self
Thompson, Neal R.	self
Thornton, Leonard	self
Thorpe, K.E	self
Thorpe, Rawley (Mr. & Mrs.)	self
Tibbets, Ken	self
Tickner, Paul R.	Indust. wkr.
Tilbury, Verl	self
Tindall, Willie	Indust. wkr.
Tindall, Willie (Mrs.)	self
Titus, Audrey	self
Titus, Don	Indust. wkr.
Titus, John M.	Indust. wkr.
Tobie, Gene L.	Indust. wkr.
Todahl, Andy R.	Indust. wkr.
Todahl, James E.	Indust. wkr.
Todd, Edgar R.	Indust. wkr.
Todd, Melvin B.	Indust. wkr.
Tofte, Bernard	Indust. wkr.
Tofte, Margie	self
*Toombs, Fred R.	Col. Basin Elec. Coop. Inc
Tommerup, Steven P.	Indust. wkr.
Tommerup, Steven P.	Indust. wkr.
Tommerup, Steven P.	self
*Torrend, Palmer S.	Tualtin Valley Irrigation District
Trahous, Phyllis	self
Trammell, William C.	Indust. wkr.
Traphouse, Michael C.	self
Tresch, Herman & Mary	self
Tresselt, Otto F.	Indust. wkr.
Trevis, Jim	self
Trueax, Russell & family	self
Truelove, Tom	City of Cheney
Trull, Darrell A.	Indust. wkr.
Trull, Dennis M.	Indust. wkr.
Tsubota, Gene	self
Tucker, Pat	self
Tudor, Betty, Mark, Tim	Irrigator
Turvur, Bob & Elenora	self
Twidwell, Dean	Indust. wkr.
Twidwell, Joan	self
Ubl, Judy	self
Udy, Irene	self
Ulmer, Derald	self
Ulrich, Virginia	self
Ulrich, Warren J.	self
Umbaugh, David S.	Indust. wkr.
Umbaugh, Sam J.	Indust. wkr.
Ungrieht, Ralph	self
Unick, Gerald D.	Indust. wkr.
Uough, Darlene	Indust. wkr.
Ushn, David A.	Indust. wkr.
Utecht, Glen E.	Indust. wkr.
Utley, Harold D.	self
Vaday, Lou	self
Vail, Martin R.	Indust. wkr.
Valandry, Richard B.	Indust. wkr.
Van Every, Donald J.	Indust. wkr.
Van Gilder, Arlyn	self
Van Gilder, Arlyn (Mrs.) (2 letters)	self
VanBeek, Conrad	Indust. wkr.
VanWeenhuz, Cindy	self
Vancouver, City of Jim Justin	self
Vandegraff, Donald R.	Indust. wkr.
Vareberg, Darrell	self
Varga, Frank	Indust. wkr.
Vasseur, Hazel R. & Marc G.	self
Vaughn, John	self
Vaughn, John	self
Veach, Thos. R.	self

Individual	Representing
Veenstra, Robert L.	Indust. wkr.
Veliz, Marcelino	Indust. wkr.
Vermillion, Larry D.	Indust. wkr.
Victor, Robert E.	self
Villavicencio, Frank A.	Indust. wkr.
Vines, Leon (Mrs.)	self
Vineyard, Kenneth A.	Indust. wkr.
Visser, Gerald W.	Indust. wkr.
Vit, Henry G. Jr.	Indust. wkr.
Voeller, Ken	Indust. wkr.
Vogel, Leo F.	Irrigator
Vogelzang, Mel	Indust. wkr.
Vooge, Ronald J.	Indust. wkr.
Vuylsteke, Eugene J.	Indust. wkr.
Wade, Clifford E.	self
Wade, James L.	Indust. wkr.
Wageman, Janet	self
Wageman, Larry	Indust. wkr.
Wageman, Phil (Mr. & Mrs.)	self
Wageman, Sandra	self
*Wagner, Byron	Big Bend Elec. Coop, Inc.
Wagner, Edwin E.	Indust. wkr.
Wagoner, Grace	self
Wahl, Leonard J.	Indust. wkr.
Waite, Roger L.	Indust. wkr.
Walburn, Richard R.	Indust. wkr.
Wallace, Donald I	Indust. wkr.
Wallace, Mary	self
Walser, Steven C.	Indust. wkr.
Walter, Gene H.	self
Walter, Lewis B.	self
Waltermire, Jim	Mont. Sec. of State
Wammock, L. (Mrs.)	self
Wandling, Lyle	Irrigator
Wanner, Julius	Indust. wkr.
Wapato, S. T.	Col. River Inter-Tribal Fish Comm.
Ward, Dale & Yvonne	self
Ward, Dana L.	self
Ward, John F.	Indust. wkr.
Ward, Judy	self
Ward, Larry N.	self
Ward, Leon	Indust. wkr.
Ward, Pat	self
Ward, Scott	Indust. wkr.
Warner, Thomas K.	Indusrial worker
Warren, Wayne	self
Washington, Howard	self
Waters, Robert J.	Indust. wkr.
Watson, Barry A.	Detrio Grange #828
Watson, Darrell Jr.	self
Watz, Joe F.	Indust. wkr.
Waugh, Carol A.	self
Weaver, Rhonda	Indust. wkr.
Weber, Mike	Jefferson Cty Agriculture
Weed, Herbert R.	self
Weefle, Michael	Indust. wkr.
Weidert, J & J	Irrigator
Weippert, Billy D.	Indust. wkr.
Weisenburger, Kenneth A.	Indust. wkr.
Welp, J. P.	Indust. wkr.
Wendel, Roger J.	self
West, Butch	Indust. wkr.
West, Diana	self
West, Dick C. (Mrs.)	self
West, Harry	self
West, Larry	Indust. wkr.
Westhoff, Donald	Indust. wkr.
Westman, Steve	Indust. wkr.
Wetmore, Marlene	self
Wetmore, Pete	self
Wheeler, Larry E.	Indust. wkr.
White, Alvin A.	Indust. wkr.
White, Carol Ann	self
White, E. L.	self
White, Jack E.	self

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Individual	Representing
White, Jake	self
White, Lonnie W.	indust. wkr.
Whitecotton, M. W. (Mrs.)	self
Whitner, Kathy	self
Whitner, Ken (Mrs.) (2 letters)	self
Whitsler, Bill A.	self
Whitton, Mayor W.F (with petitions)(2 letters)	City of Rupert
Whittaker, David E.	self
Wiegand, James A.	indust. wkr.
Wiesenmayer, Andrew	indust. wkr.
Wilcox, Richard	indust. wkr.
Wilkerson, Bill	indust. wkr.
Wilkerson, Carl	indust. wkr.
Willett, Michael L.	indust. wkr.
Williams, Bob	Wash. Representative
Williams, Jack C.	indust. wkr.
Williams, K. C.	labor organization
Williams, Ken W.	indust. wkr.
Williams, Lisa & Lonnie	self
Williams, M. M.	self
Williams, Scott & Tracy	indust. wkr.
Williams, Warren A.	indust. wkr.
Williamson, C. R.	irrigator
Willits, Howard D.	self
Willsey, John	self
Wilson, Claude A.	indust. wkr.
Wilson, D. C.	self
Wilson, George O.	self
Wilson, Gerald L.	indust. wkr.
Wilson, Joe (Mrs.)	self
Wilson, Julia	self
Wilson, Paul D.	indust. wkr.
Wilson, R. Mark	indust. wkr.
Wilson, Tomorrow J.	self
Winter, Vera	self
Winterfield, Brian	self
Winterfield, Don	indust. wkr.
Winters, Gina (2 letters)	self
Wise, J. C. (Mr. & Mrs.)	self
Wise, Perry L.	indust. wkr.
Wissinger, M. Tom	indust. wkr.
Wistisen, Martin J. (2 letters)	irrigator
Witt, Jerry	indust. wkr.
Witt, Patricia	self
Wohlers, Mayor J. Robert & Council (with petitions)	City of Mossy Rock
Wojcik, Dolores	self
Wolner, George R.	indust. wkr.
Wommack, Larry (Mrs.)	indust. wkr.
Wood, Stanley C.	indust. wkr.
Woodell, James M.	indust. wkr.
Woodmansee, Charles & Betty	self
Woodside, Vanda	self
Woodward, Rollan S.	indust. wkr.
Wooten, N. J.	self
Workentin, David I.	indust. wkr.
Worthen, Gary A.	indust. wkr.
Wyatt, Kathleen M.	self
Wyatt, Tim A.	self
Wyett, Bert J.	self
Wyman, Bobby G.	indust. wkr.
Wyngaert, James	indust. wkr.
Wynne, Ben	indust. wkr.
Wynne, Ray W.	indust. wkr.
Yankancy, John	indust. wkr.
Yankee, F. W.	self
Yarington, Gail J. (2 letters)	indust. wkr.
Yarington, Shirley	self
Yarnell, Debbie	indust. wkr.
Yockey, Kathi	self
Yocom, Lillian	self
Yokey, Sam	self
Yonkers, Minnie	self
Yost, Warren C.	indust. wkr.
Younce, Dan	self

Individual	Representing
Young, Gay	self
Young, Josie M.	self
Young, Muriel (2 letters)	self
Young, Myrle (Mr. & Mrs.)	self
Young, P. W.	indust. wkr.
Young, William C.	self
Young, William R.	indust. wkr.
Young, Wm. C. & Claudia	self
Zaferin, Nick J.	indust. wkr.
Zanich, Andrew	indust. wkr.
Zauft, Richard D. (2 letters)	self
Zourkos, D. Jim	indust. wkr.
Zuercher, Lanny L.	indust. wkr.

Comments Made by Telephone

Dietrich, Henry	indust. wkr.
McLeod, Robert	indust. wkr.
Vaughn, John	self
O'Connell, Michael	self
Rickman, Harley & Jean	self
Turvus, Bob & Elenora	self
Burns, Mike	self
Garner, Dave	self
Houston, Coleen	self
Jackson, Lois	self
Rolland (Mrs.)	self
Fletcher, Zelma	self
Murry, Rodney D. (Mrs.)	self
Puttman, David	self
Duckman, Doris	self
Greenside, Robert	indust. wkr.
McLellan, Larry	Committe of 1700
Medlin, J.D.	self
Rizzo, Tom	self
Cain, James	self
Johnson, Mary (Mrs.)	self

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APPENDIX D

WHOLESALE POWER RATE SCHEDULES

SCHEDULE PF-83

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest.

Priority Firm Power may be purchased for resale, direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) may purchase Priority Firm Power pursuant to the Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $5.57 per kilowatt of billing demand;

2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.42 per kilowatt of billing demand;

3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March: 15.9 mills per kilowatthour of billing energy;

2. for the billing months April through August: 12.7 mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.

2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

In this section billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), metered requirements purchasers and those priority firm purchasers not covered by sections III.A and III.B (section III.C), and all purchasers of Priority Firm Power during a period of insufficiency (section III.D). If BPA has provided the purchaser with notice of insufficiency, the billing provisions of section III.D shall take precedence over the billing provisions of sections III.A, III.B, and III.C.

A. Computed Requirements Purchasers

Purchasers designated by the Bonneville Power Administration (BPA) as computed requirements purchasers either pursuant to section IV.B.1.b of the General Rate Schedule Provisions or pursuant to power sales contracts executed after December 5, 1980, shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

a. Basic Service

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the following billing factors:

(1) the lower of:
- (a) the Measured Demand, before adjustment for power factor; or
- (b) the Computed Maximum Requirement which is the larger of the Computed Peak Requirement or the Computed Average Energy Requirement, and

(2) the lower of:
   (a) the Computed Peak Requirement; or
   (b) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

b. Unauthorized Increase

That portion of any Measured Demand during the hours between 7 a.m. and 10 p.m. on any day Monday through Saturday, before adjustment for power factor, which exceeds the Computed Maximum Requirement during the billing month and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy

a. Basic Service

The billing energy for actual, planned, and contracted computed requirements purchasers shall be the lesser of:

(1) the Computed Energy Maximum, or
(2) for the months September through March, the sum of:
   45 percent of the Measured Energy, and
   55 percent of the Computed Energy Maximum;
(3) for the months April through August, the sum of:
   50 percent of the Measured Energy, and
   50 percent of the Computed Energy Maximum.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the Computed Energy Maximum for that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be eighty percent of the energy associated with the utility's residential load for each billing period through June 30, 1984. The percentage shall be increased to 90 percent on July 1, 1984, and to 100 percent on July 1, 1985.

C. Metered Requirements Purchasers and Other Purchasers not covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

a. Basic Service

For metered requirements purchasers the billing demand shall be the Measured Demand as adjusted for power factor.

Other purchasers shall be billed on the Contract Demand, if such demand is specified in the power sales contract. Otherwise the billing demand for such purchasers shall be the Measured Demand as adjusted for power factor.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the amount of firm power the purchaser is entitled to take pursuant to the power sales contract and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed as unauthorized increase.

2. Billing Energy

a. Basic Service

For metered requirements purchasers the billing energy shall be the Measured Energy.

Other purchasers shall be billed on the Contract Demand multiplied by the number of hours in the billing month, provided a Contract Demand is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take pursuant to the power sales contract during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed as unauthorized increase.

D. Purchasers of Priority Firm Power During a Period of Insufficiency

In the event of an insufficiency of electric power, all purchasers of Priority Firm Power who are contractually limited to an allocation of capacity and/or energy, as determined by BPA pursuant to the terms of the purchaser's power sales contract, shall be billed as follows:

1. Billing Demand, Given an Allocation of Firm Capacity

a. Basic Service

If there has been an allocation of Firm Capacity, the billing demand shall be the lower of:

(1) the Measured Demand as adjusted for power factor; or
(2) the allocation of Firm Capacity, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the allocation of Firm Capacity and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy, Given an Allocation of Firm Energy

a. Basic Service

If there has been an allocation of Firm Energy, the billing energy shall be the lower of:

(1) the Measured Energy; or
(2) the allocation of Firm Energy, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the allocation of Firm Energy for that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

3. Billing Factors, Given No Allocation of Firm Capacity and/or No Allocation of Firm Energy

The billing demand or billing energy, if not specifically limited to an allocation pursuant to the purchaser's power sales contract, shall be determined according to the appropriate section, III.A, III.B, or III.C, above.

SECTION IV. ADJUSTMENTS:

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

1. Basic LDD Principles

A predetermined discount shall be applied each month of a calendar year to the charges for power purchased under this rate schedule by eligible purchasers as defined in section IV.B.2., below. The discount shall be based on the following ratios:

a. the purchaser's total electric energy requirements during the previous calendar year (including the purchaser's nonfirm sales and sales for resale) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

b. the average number of residential consumers during the previous calendar year divided by the number of pole miles of distribution line at the end of such year.

In calculating these ratios BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

2. Eligibility Criteria

To quality for a discount, the purchaser must meet all five of the following eligibility criteria:

a. the purchaser must serve as an electric utility offering power for resale;
b. the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the BPA region;
c. the purchaser's kilowatthour to investment ratio (Ratio IV.B.1.a) must be less than 100;
d. the purchaser's consumers per mile ratio (Ratio IV.B.1.b) must be less than 10; and
e. the purchaser must qualify for a discount based on the criteria in section IV.B.3, below.

3. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for each are listed below.

a. Three percent
   For any purchaser for whom:
   (1) the kilowatthour to investment ratio is equal to or greater than 25 but less than 35; or
   (2) the consumers per mile ratio is equal to or greater than 4 but less than 6.

b. Five percent
   For any purchaser for whom:
   (1) the kilowatthour to investment ratio is equal to or greater than 15 but less than 25; or
   (2) the consumers per mile ratio is equal to or greater than 2 but less than 4.

c. Seven percent
   For any purchaser for whom:
   (1) the kilowatthour to investment ratio is less than 15; or
   (2) the consumers per mile ratio is less than 2.

C. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule.

For this rate schedule, the variable ECP in the Exchange Adjustment calculation shall have a value of .254.

D. Supply System Adjustment

The Supply System Adjustment shall be calculated pursuant to section III.C.3 of the General Rate Schedule Provisions. The Adjustment shall be applied to the energy component of the Priority Firm Power Rate and shall be in effect from July 1, 1984, through the end of the rate period.

For this rate schedule, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = .935;
2. BD = 75,780.

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the PF-83 rate is 82 percent FBS and 18 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE IP-83

INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available to existing direct-service industrial customers for the contract purchase of Industrial Firm Power on an Operating Demand basis and for Auxiliary Power requested by the purchaser and made available as an Auxiliary Demand by BPA on an intermittent basis. This rate schedule supersedes Schedule IP-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes three possible rates for Industrial Firm Power basic service: the Standard Industrial Rate, the Premium Industrial Rate, and the Industrial Incentive Rate. Under the Standard Industrial Rate, first quartile service is provided by BPA with nonfirm energy and/or provisional drafts. Under the Premium Industrial Rate, first quartile service is provided with surplus firm energy load carrying capability (FELCC). The Industrial Incentive Rate is for the same quality of service as provided under the Standard Industrial Rate, but the rate is optional at the discretion of the Administrator, with the agreement of affected direct-service industrial customers and is applied on a take-or-pay basis. The procedures for determining when the Industrial Incentive Rate will be offered are specified in section V.D of the General Rate Schedule Provisions.

A. Standard Industrial Rate

The following rate shall apply to purchases of Industrial Firm Power under the Standard Industrial Rate:

1. Customer Charge:

   a. for all billing months: $7.34 per kilowatt. The basis for the customer charge is provided in section III.A of this rate schedule.

2. Demand Charge:

   a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $4.62 per kilowatt of billing demand;
   b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.21 per kilowatt of billing demand;

c. all other hours: No demand charge.

3. Energy Charge:

a. for the billing months September through March: 14.7 mills per kilowatthour of billing energy;
b. for the billing months April through August: 12.2 mills per kilowatthour of billing energy.

4. Unauthorized Increase Charge:

a. 83.0 mills per kilowatthour.

B. Premium Industrial Rate

The following rate shall apply to purchases of Industrial Firm Power under the Premium Industrial Rate:

1. Customer Charge:

a. for all billing months: $9.63 per kilowatt. The basis for the customer charge is provided in section III.A of this rate schedule.

2. Demand Charge:

a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $5.57 per kilowatt of billing demand;
b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.42 per kilowatt of billing demand;
c. all other hours: No demand charge.

3. Energy Charge:

a. for the billing months September through March: 15.9 mills per kilowatthour of billing energy;
b. for the billing months April through August: 12.7 mills per kilowatthour of billing energy.

4. Unauthorized Increase Charge:

a. 83.0 mills per kilowatthour.

C. Industrial Incentive Rate

If BPA elects to implement the Industrial Incentive Rate, the rate shall be contractually specified. The rate which is adopted shall remain in effect for at least 6 months or the end of the rate period, whichever comes first.

1. <u>Customer Charge</u>:

for all billing months: $7.34 per kilowatt. The basis for the customer charge is provided in section III.A of this rate schedule.

2. <u>Demand Charge</u>:

The demand charge for the Industrial Incentive Rate shall be contractually specified and shall be calculated by reducing the demand charge for the Standard Industrial Rate by a uniform percentage.

3. <u>Energy Charge</u>:

The energy charge for the Industrial Incentive Rate shall be contractually specified and shall be calculated by reducing the energy charge for the Standard Industrial Rate by a uniform percentage.

4. <u>Unauthorized Increase Charge</u>:

83.0 mills per kilowatthour.

SECTION III. BILLING FACTORS:

A. <u>Customer Charge</u>

The Customer Charge shall be applied on a monthly basis to purchasers of Industrial Firm Power. The Customer Charge for power purchased under all three rates (the Standard Industrial Rate, the Premium Industrial Rate, and the Industrial Incentive Rate shall be based on the greater of:

1. the weighted average of Restricted Demand, if any, and 89.4 percent of Monthly Operating Demand; or

2. Billing Demand.

B. <u>Billing Demand</u>

1. <u>Basic Service</u>

a. <u>Standard Industrial Rate and Premium Industrial Rate</u>

For customers purchasing under either the Standard Industrial Rate or the Premium Industrial Rate, the billing demand for Industrial Firm Power basic service shall be the lowest of the following billing factors:

(1) Operating Demand;
(2) Curtailed Demand; or
(3) Restricted Demand.

b. Industrial Incentive Rate

For customers purchasing under the Industrial Incentive Rate, the billing demand for Industrial Firm Power basic service shall be the greater of billing factors (1) and (2):

(1) (a) Curtailed Demand, if applicable; otherwise,
(b) Operating Demand; and

(2) the lower of:
(a) Committed Demand; or
(b) Restricted Demand.

c. Application of the Billing Factors for Basic Service

Each of the billing factors for demand used in the computation of the power bill shall be adjusted for power factor. Only that portion of the demand which is purchased from BPA shall be considered in the determination of the billing demand.

If, during any billing month, there is more than one type of demand (Operating Demand, Curtailed Demand, Restricted Demand, or Committed Demand) for Industrial Firm Power basic service, the billing demand for Industrial Firm Power basic service shall be the weighted average of the billing demands for power purchased under this rate schedule for basic service during such month.

If the purchaser requests a waiver regarding the notice requirements specified in the purchaser's power sales contract for a voluntary change in the level of Operating Demand or Curtailed Demand, and if BPA does not grant the waiver, or if the purchaser fails to give notice of such a change and does not request a waiver, the purchaser shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

2. Auxiliary Power

For Auxiliary Power requested by the purchaser and made available by BPA, the billing demand shall be the weighted average of the purchaser's Auxiliary Demands during the billing month, as adjusted for power factor. Auxiliary Power shall be made available to the purchaser at the same rate (either at the Standard Industrial Rate, the Premium Industrial Rate, or the Industrial Incentive Rate) as that applied to the purchaser's basic service.

3. Curtailments

BPA shall charge the purchaser for curtailments in accordance with the provisions of section 9 of the power sales contract.

4. Unauthorized Increase

If the Measured Demand during the hours 7 a.m. - 10 p.m. on any day Monday through Saturday exceeds the sum of:

a. the billing demand (as specified in section III.B.1) during that hour before adjustment for power factor;
b. the Auxiliary Demand during that hour before adjustment for power factor; and
c. any applicable demands which the purchaser acquires through other contracts for such hour;

the difference may be billed:

a. as unauthorized increase; or
b. as additional billing demand under this rate schedule.

BPA shall make the determination as to how the unauthorized increase shall be billed.

5. Transitional Service

Transitional Service may only be purchased under the Standard Industrial Rate or the Premium Industrial Rate.

If the purchaser requests billing on a Measured Demand basis pursuant to section 4 of the power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the weighted average of the daily Measured Demands as adjusted for power factor. However, at no time during the period of restoration, as defined in section 4(e) of the power sales contract, shall the daily demand be lower than any previous such demand during such period. Should the Measured Demand for any day during the period of restoration be lower than the daily demand for the previous day, the previous day's daily demand shall be used as the daily demand for such day.

C. Billing Energy

1. Basic Service

a. Standard Industrial Rate and Premium Industrial Rate

The billing energy shall be the Measured Energy for the billing month.

b. Industrial Incentive Rate

The billing energy shall be the higher of:

(1) the Committed Energy; or
(2) the Measured Energy for the billing month.

The power bill shall reflect the distribution of the kilowatthours of billing energy among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE IP-83 RATE FOR BASIC SERVICE:

All sales of Industrial Firm Power for which there is no contract specifying use of the Premium Industrial Rate or the Industrial Incentive Rate shall be made at the Standard Industrial Rate.

If the purchaser elects to purchase Industrial Firm Power under the Premium Industrial Rate, BPA and the purchaser shall execute a contract specifying the period of time for which the Premium Industrial rate shall be effective.

The Industrial Incentive Rate shall only be applied to sales of Industrial Firm Power made pursuant to contracts specifying use of the Industrial Incentive Rate. Prior to applying the Industrial Incentive Rate, BPA and the purchaser shall contractually specify the terms and conditions under which the incentive rate shall apply. The contract with the purchaser shall specify:

A. the period of time for which the Industrial Incentive Rate is to be applied (such period being for no less than 6 months);
B. the Committed Demand;
C. the Committed Energy; and
D. the level of the demand and energy charges.

During any billing month only one of the three possible rates for Industrial Firm Power basic service may apply (Standard Industrial Rate, Premium Industrial Rate, and Industrial Incentive Rate). The rate in effect on the first day of the billing month shall remain in effect for the entire billing month.

SECTION V. ADJUSTMENTS:

A. Value of Reserves

A monthly billing credit for the value of the reserves provided by purchasers of Industrial Firm Power under the Standard Industrial Rate and the Premium Industrial Rate shall be:

1. \$0.23 per kilowatt of billing demand; and
2. 1.6 mills per kilowatthour of billing energy.

The credit for power purchases under the Standard Industrial Rate and the Premium Industrial Rate shall be applied to the same billing factors which are used to determine the billing for power purchased under sections III.B.1, III.B.2, and III.C.1 of this rate schedule. No value of reserves credit shall be applied to that portion of the purchaser's demand subject to curtailment charges under section III.B.3 of this rate schedule. In addition, no value of reserves credit shall be applied to those purchases subject to unauthorized increase charges under section III.B.4, above.

No value of reserves credit shall be applied to purchasers of Industrial Firm Power under the Industrial Incentive Rate.

B. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

C. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under the Standard Industrial Rate and the Premium Industrial Rate.

For this rate schedule, the variable ECP in the Exchange Adjustment calculation shall have a value of .521.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the IP-83 rate is 100 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE IH-83

INDUSTRIAL HANNA RATE

SECTION I. AVAILABILITY:

This schedule is available for the Hanna Nickel Smelting Company's contract purchase of a special class of Industrial Power on an Operating Demand basis and for Auxiliary Power requested by the purchaser and made available as an Auxiliary Demand by BPA on an intermittent basis. This rate schedule is made available pursuant to section 7(d)(2) of the Pacific Northwest Electric Power Planning and Conservation Act. This schedule supersedes Schedule SI-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes two possible rates for Industrial Hanna basic service: the Standard Industrial Hanna Rate and the Offpeak Industrial Hanna Rate. The Standard Industrial Hanna Rate is available for full service provided during BPA's peak and offpeak periods. The Offpeak Industrial Hanna Rate is available for special offpeak service requested by the purchaser.

A. Standard Industrial Hanna Rate

1. Demand Charge:

    a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $5.57 per kilowatt of billing demand;
    b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.42 per kilowatt of billing demand;
    c. all other hours: No demand charge.

2. Energy Charge:

    a. for the billing months September through March: 15.9 mills per kilowatthour of billing energy;
    b. for the billing months April through August: 12.7 mills per kilowatthour of billing energy.

3. Unauthorized Increase Charge:

    a. 83.0 mills per kilowatthour.

B. Offpeak Industrial Hanna Rate

1. Demand Charge

   a. for all hours: No demand charge.

2. Energy Charge

   a. for all billing months: 7 mills per kilowatthour of billing energy.

3. Unauthorized Increase Charge

   a. 83.0 mills per kilowatthour.

SECTION III. BILLING FACTORS:

A. Billing Demand

1. Basic Service:

   a. Standard Industrial Hanna Rate

   BPA shall base the billing demand for the Standard Industrial Hanna Rate on the lowest of the following billing factors for the billing month:

   (1) Operating Demand;
   (2) Curtailed Demand; or
   (3) Restricted Demand.

   Each of the billing factors for demand used in the computation of the power bill shall be adjusted for power factor. Only that portion of the demand which is purchased from BPA shall be considered in the determination of the billing demand.

   If the purchaser requests a waiver regarding the notice requirements specified in the purchaser's power sales contract for a voluntary change in the level of Operating Demand or Curtailed Demand, and if BPA does not grant the waiver, or if the purchaser fails to give notice of such a change and does not request a waiver, the purchaser shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

During any billing month in which there is more than one type of demand (Operating Demand, Curtailed Demand, or Restricted Demand) for basic service for this special class of Industrial Power, the billing demand for basic service shall be the weighted average of the billing demands for power purchased under this rate schedule for basic service during such month.

b. Offpeak Industrial Hanna Rate

There is no billing demand for purchases under the Offpeak Industrial Hanna Rate.

2. Auxiliary Power:

For Auxiliary Power requested by the purchaser and made available by BPA, the billing demand shall be the weighted average of the purchaser's Auxiliary Demands during the billing month, as adjusted for power factor.

3. Curtailments:

BPA shall charge the purchaser for curtailments in accordance with the provisions of section 9 of the power sales contract.

4. Unauthorized Increase:

a. Standard Industrial Hanna Rate

If the purchaser is being served under the Standard Industrial Hanna rate and if the Measured Demand during the hours 7 a.m. - 10 p.m. on any day Monday through Saturday exceeds the sum of:

(1) the billing demand (as specified in section III.A.1) during that hour before adjustment for power factor;
(2) the Auxiliary Demand during that hour before adjustment for power factor; and
(3) any applicable scheduled demands which the purchaser acquires through other contracts for such hour,

the difference may be billed:

(1) as unauthorized increase; or
(2) as additional billing demand under this rate schedule.

BPA shall make the determination as to how the unauthorized increase shall be billed.

b. Offpeak Industrial Hanna Rate

If the purchaser being served under the Offpeak Industrial Hanna Rate requests more than 10 percent of Contract Demand during other than the specified offpeak period, such deliveries may be billed as an unauthorized increase. BPA shall make the determination as to how the unauthorized increase shall be billed.

5. Transitional Service:

If the purchaser requests billing on a Measured Demand basis pursuant to section 4 of the power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the weighted average of the daily Measured Demands as adjusted for power factor. However, at no time during the period of restoration, as defined in section 4(e) of the power sales contract, shall the daily demand be lower than any previous such demand during such period. Should the Measured Demand for any day during the period of restoration be lower than the daily demand for the previous day, the previous day's demand shall be used as the daily demand for such day.

B. Billing Energy

The billing energy under both the Standard and Offpeak Industrial Hanna Rates shall be the Measured Energy for the billing month.

The power bill shall reflect the distribution of the kilowatthours of billing energy among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE IH-83 RATE:

The purchaser may select one of two service options, standard service or offpeak service. BPA will provide standard service under the Standard Industrial Hanna Rate and offpeak service under the Offpeak Industrial Hanna Rate. Unless BPA receives a formal request for service under the Special Offpeak Industrial Hanna Rate, all service will be standard service provided under the Standard Industrial Hanna Rate. To change the type of service provided and the associated rate, the purchaser shall submit a formal request for service under the preferred rate option in accordance with the terms of the purchaser's power sales contract. Once a purchaser has elected to purchase under one of the two options, all purchases of special industrial power shall be subject to the terms and conditions of that rate option until such time as the purchaser requests the other type of service.

SECTION V. OFFPEAK SERVICE:

BPA shall designate the hours during which offpeak service will be available, and shall provide the purchaser with at least 2 weeks notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If the purchaser has elected to be served under the Offpeak Industrial Hanna Rate, the purchaser may request, during the designated offpeak periods, service in an amount not to exceed the purchaser's Contract Demand. During all other hours the purchaser shall curtail service to a level not to exceed 10 percent of Contract Demand.

SECTION VI. ADJUSTMENTS:

A. Value of Reserves

1. Standard Industrial Hanna Rate

An adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power shall be:

a. \$0.23 per kilowatt of billing demand; and
b. 1.6 mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under sections III.A.1.a, III.A.2, and III.B of this rate schedule. No value of reserves credit shall be applied to that portion of the purchaser's demand subject to curtailment charges under section III.A.3 or to those purchases subject to unauthorized increase charges under section III.A.4 of this rate schedule.

2. Offpeak Industrial Hanna Rate

No value of reserves credit shall be applied to purchases under the Offpeak Industrial Hanna Rate.

B. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Standard Industrial Hanna Rate, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the offpeak Industrial Hanna rate, BPA shall increase the billing energy by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION VII. RESOURCE COST CONTRIBUTION:

The IH-83 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VIII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE CF-83

FIRM CAPACITY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Firm Capacity without energy on a Contract Demand basis. BPA may supply Firm Capacity:

A. on a contract year basis (all 12 months of the year);
B. on a contract season basis (June 1 through October 31); or
C. on a general basis (where the months during which Firm Capacity will be supplied are specified in the power sales contract).

This schedule supersedes Schedule CF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Contract Year Service

$44.76 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.73 per kilowatt of Contract Demand.

B. Contract Season Service

$12.10 per kilowatt per season of Contract Demand, billed monthly during the contract season at the rate of $2.42 per kilowatt of Contract Demand.

C. General Service

1. for the billing months December through April:
$5.57 per kilowatt of Contract Demand;

2. for the billing months May through November:
$2.42 per kilowatt of Contract Demand,

BPA shall bill purchasers of general Firm Capacity service at the applicable monthly rate, as given in C.1 and C.2, above. Bills shall be rendered only for the months during which BPA has contracted with the purchaser to supply Firm Capacity.

D. Intertie Service

The monthly capacity rate specified in subsections A, B, and C, above, shall be increased by $.12 per kilowatt for capacity made available at the Oregon-California or the Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

E. Extended Peaking Surcharge

The monthly capacity rate specified in subsections A, B, and C, above, shall be increased by $0.048 per kilowatt of billing demand for each hour that the purchaser's monthly demand duration exceeds 9 hours. The charge shall be prorated for each portion of an hour of extended peaking supplied to the purchaser. The purchaser's demand duration for the month shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by

2. the purchaser's Contract Demand for such month.

The additional charge described above shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

SECTION III. BILLING FACTORS:

The billing demand shall be the Contract Demand.

SECTION IV. SPECIAL PROVISION:

Contracts for the purchase of Firm Capacity under this schedule shall include provisions for the purchaser to replace the energy accompanying the delivery of such capacity.

SECTION V. ADJUSTMENTS:

A. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule.

For contract year and general service, the variable ECP in the Exchange Adjustment calculation shall have a value of .013.

For contract season service, the variable ECP in the Exchange Adjustment calculation shall have a value of .001.

B. Supply System Adjustment

The Supply System Adjustment shall be calculated pursuant to section III.C.3 of the General Rate Schedule Provisions. The Adjustment shall be applied to the demand component of the Firm Capacity Rate, and shall be in effect from July 1, 1984, through the end of the rate period.

For contract year and general service, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = .026;
2. BD = 17,724.

For contract season service, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = .002;
2. BD = 3,000.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the CF-83 rate is 75 percent FBS and 25 percent Exchange for contract year service, and 85 percent FBS and 15 percent Exchange for contract season service.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE CE-83

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY:

This schedule is available for the purchase of capacity:

A. when an emergency exists on the purchaser's system, or
B. when the purchaser wishes to displace higher cost firm capacity resources which are otherwise available to meet the purchaser's load

provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Demand Charge

$1.12 per kilowatt of demand per calendar week or portion thereof.

B. Intertie Charge

The demand charge specified above shall be increased by $0.03 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS:

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD:

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION:

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the CE-83 rate is 75 percent FBS and 25 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE NR-83

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest.

New Resource Firm Power is available to those investor-owned utilities under net requirements contracts purchasing firm power for resale, direct consumption, or use in construction, test and start up, and station service.

New Resource Firm Power is also available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any increase in energy consumption of a load as defined in section 3.(13) of the Pacific Northwest Electric Power Planning and Conservation Act as interpreted in Notice of Final Action (46 F.R. 44353)(September 3, 1981).

In addition, BPA may make this rate available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule NR-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $5.57 per kilowatt of billing demand;

2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.42 per kilowatt of billing demand;

3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March: 26.3 mills per kilowatthour of billing energy;

2. for the billing months April through August: 21.0 mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.

2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

In this section billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), metered requirements purchasers and those New Resource Firm Power purchasers not covered by section III.A (section III.B), and purchasers of New Resource Firm Power during a period of insufficiency (section III.C). If BPA has provided the purchaser with notice of insufficiency, the billing provisions of section III.C shall take precedence over the billing provisions of sections III.A and III.B.

A. Computed Requirements Purchasers

Purchasers designated by the Bonneville Power Administration (BPA) as computed requirements purchasers pursuant to power sales contracts executed after December 5, 1980, shall be billed in accordance with the provisions of this section.

1. Billing Demand

a. Basic Service

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the following billing factors:

(1) the lower of:
   (a) the Measured Demand, before adjustment for power factor; or
   (b) the Computed Maximum Requirement which is the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; and

(2) the lower of:
    (a) the Computed Peak Requirement; or
    (b) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

b. Unauthorized Increase

That portion of any Measured Demand during the hours between 7 a.m. and 10 p.m. on any day Monday through Saturday, before adjustment for power factor, which exceeds the Computed Maximum Requirement during any billing month and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy

a. Basic Service

The billing energy for actual, planned, and contracted computed requirements purchasers shall be the lesser of:

(1) the Computed Energy Maximum; or
(2) for the months September through March, the sum of:
    27 percent of the Measured Energy, and
    73 percent of the Computed Energy Maximum;
(3) for the months April through August, the sum of:
    34 percent of the Measured Energy, and
    66 percent of the Computed Energy Maximum.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the Computed Energy Maximum for that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Metered Requirements Purchasers and Other Purchasers not covered by Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

a. Basic Service

For metered requirements purchasers the billing demand shall be the Measured Demand as adjusted for power factor.

Purchasers who previously utilized the Firm Energy Rate Schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

Other purchasers shall be billed on the Contract Demand if specified in the power sales contract. Otherwise the billing demand for such purchasers shall be the Measured Demand as adjusted for power factor.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the amount of firm power the purchaser is entitled to take pursuant to the power sales contract and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed as unauthorized increase.

2. Billing Energy

a. Basic Service

For metered requirements purchasers the billing energy shall be the Measured Energy.

Other purchasers shall be billed on the Contract Demand multiplied by the number of hours in the billing month, provided a Contract Demand is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take pursuant to the power sales contract during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed as unauthorized increase.

C. Purchasers of New Resource Firm Power during a Period of Insufficiency

In the event of an insufficiency of electric power, all purchasers of New Resource Firm Power who are contractually limited to an allocation of capacity and/or energy, as determined by BPA pursuant to the terms of the purchaser's power sales contract, shall be billed as follows:

1. Billing Demand, Given an Allocation of Firm Capacity

a. Basic Service

If there has been an allocation of firm capacity, the billing demand shall be the lower of:

(1) the Measured Demand as adjusted for power factor; or
(2) the allocation of firm capacity, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the allocation of firm capacity and which cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy, Given an Allocation of Firm Energy

a. Basic Service

If there has been an allocation of firm energy, the billing energy shall be the lower of:

(1) the Measured Energy; or
(2) the allocation of firm energy, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the allocation of firm energy for that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

3. Billing Factors, Given No Allocation of Firm Capacity and/or No Allocation of Firm Energy

The billing demand or billing energy, if not specifically limited to an allocation pursuant to the purchaser's power sales contract, shall be determined according to the appropriate section, III.A or III.B, above.

SECTION V. ADJUSTMENTS:

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of .002.

SECTION VII. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the NR-83 rate is 100 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VIII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE SP-83

SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Surplus Firm Power to be used either for resale or direct consumption. Surplus Firm Power may be sold to entities inside and outside the Pacific Northwest as well as outside the United States. However, this rate schedule shall not apply to contracts for which rates have been negotiated pursuant to section 7(l) of the Regional Act. In addition, this schedule is not available to any direct-service industrial purchaser who buys power either under rate Schedule IP-83 or Schedule IH-83. Schedule SP-83 supersedes Schedule SP-1 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

The rate for Surplus Firm Power shall be mutually agreed upon and contractually specified by the parties prior to delivery of the power. A contract having an effective term of less than one year and terminating on or before June 30, 1985, may reference any of the four rates described below (Thermal Resource Rate, Exchange Resource Rate, Purchased Power Rate, or Contract Rate). A contract having an effective term of more than one year or terminating after June 30, 1985, shall reference the Contract Rate. Rates derived under the Thermal Resource Rate, Exchange Resource Rate, and the Purchased Power Rate may be combined to determine a weighted average rate at which Surplus Firm Power may be offered for sale.

A. Thermal Resource Rate

A Surplus Firm Power rate based on the cost of thermal resources shall be set at a level which will recover BPA's forecasted cost of generating and transmitting power from one or more Federal system thermal resources to the contractually specified point of delivery. A Thermal Resource Rate shall include all the variable costs and up to 100 percent of the fixed costs associated with generating and transmitting such thermal power.

The following variable costs, if applicable, shall be included in the determination of a Thermal Resource Rate: (a) total fuel costs; (b) incremental costs of labor and supplies required for operation and maintenance of the thermal plant(s) providing such power; (c) incremental administrative and general expenses; (d) taxes; (e) transmission network losses (to be priced at the incremental cost of the fuel required to generate the lost power); and (f) any other related costs associated with production and transmission of such thermal power.

The fixed costs associated with the generation and transmission of such thermal power shall include, if applicable: (a) debt service, (b) capital additions; (c) taxes; (d) fixed administrative and general expenses; (e) fixed operation and maintenance expenses; (f) insurance for the facilities used in the production and transmission of this thermal power; and (g) any other fixed costs associated with the generation and transmission of such thermal power.

Prior to delivery of this thermal power, BPA shall determine what portion of the fixed costs listed above shall be included in the rate.

B. Exchange Resource Rate

A Surplus Firm Power rate based on the cost of exchange resources shall contractually specify use of one of the following costs as the basis of the charge:

a. the average cost of exchange resources of one or more utilities participating in the residential exchange; or
b. the average cost of all exchange resources.

The forecast exchange resource cost included in the determination of the 1983 Wholesale Power Rates shall be used in the calculation of this rate.

The rate shall also include identifiable delivery costs (such as losses and transmission) in the same manner as in the Thermal Resource Rate.

C. Purchased Power Rate

A Surplus Firm Power rate based on the cost of purchased power shall be the sum of:

a. the total costs to BPA of the specified purchase; and
b. any identifiable costs (such as losses and transmission costs) directly associated with such energy purchase and redelivery.

D. Contract Rate

For contracts which refer to the Contract Rate in this rate schedule in determining the rate for Surplus Firm Power, the following rate shall apply:

1. Demand Charge

(1) Monday through Saturday, 7 a.m. through 10 p.m.: \$3.85 per kilowatt of billing demand;
(2) All other hours: No demand charge.

2. Energy Charge

(1) 25.9 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS:

The billing demand and billing energy for power purchased under this rate schedule shall be the Measured Demand and the Measured Energy unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS:

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. <u>Escalation Factor</u>

The SP-83 Contract Rate shall be subject to change each July 1, beginning July 1, 1985, for all contracts which extend beyond June 30, 1985. The effective rate for each rate component of the Contract Rate shall be determined according to one of the two formulas below. Formula 1 shall apply unless otherwise contractually specified.

1. $Rate_n = Rate_{n-1} * (1 + ARG_{n-1})$

where:

$Rate_n$ = the rate in the operating year (July 1 - June 30) for which the SP-83 Contract Rate is being calculated; and

$Rate_{n-1}$ = the rate for the demand component and energy component of the SP-83 Contract Rate in the previous year (year n-1);

ARG_{n-1} = the weighted average annual rate of growth in the average cost of exchange resources in year n-1 as calculated on July 1 in year n. The average cost of exchange resources shall be based on the average system costs of C. P. National Corporation, Idaho Power Company, Montana Power Company, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light Company, and Utah Power & Light Company. If any of the seven utilities elect, pursuant to Section 10 of the Residential Purchase and Sale Agreement, to equalize rates in year n-1, the calculation of ARG shall not reflect the average system cost of such electing utility.

2. $Rate_n = Rate_{n-1} * 1.095$

where:

$Rate_n$ = the rate in the operating year (July 1 - June 30) for which the SP-83 Contract Rate is being calculated; and

$Rate_{n-1}$ = the rate for the demand component and energy component of the SP-83 Contract Rate in the previous year (year n-1).

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the SP-83 rate is 98 percent Exchange and 2 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE SE-83

SURPLUS FIRM ENERGY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Surplus Firm Energy to be used either for resale or direct consumption. Surplus Firm Energy may be sold to entities inside and outside the Pacific Northwest as well as outside the United States. However, this rate schedule shall not apply to contracts for which rates have been negotiated pursuant to section 7(1) of the Regional Act. In addition, this schedule is not available to any direct-service industrial purchaser who buys power either under rate Schedule IP-83 or Schedule IH-83. Schedule SE-83 supersedes Schedule SE-1 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

31.1 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS:

The billing energy shall be determined as provided in the purchaser's power sales contract. If BPA does not have a power sales contract in force with a purchaser, the billing energy shall be the Measured Energy.

SECTION IV. ADJUSTMENTS:

A. Power Factor

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing energy by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Escalation Factor

Schedule SE-83 shall be subject to change each July 1, beginning July 1, 1985, for all contracts which extend beyond June 30, 1985. The change in the SE-83 rate shall be determined according to one of the two formulas below. Formula 1 shall apply unless otherwise contractually specified.

1. $\text{Rate}_n = \text{Rate}_{n-1} * (1 + \text{ARG}_{n-1})$

where:

Rate_n = the rate in the operating year (July 1 - June 30) for which the SE-83 rate is being calculated;

Rate_{n-1} = the SE-83 rate in the previous year (year n-1);

ARG_{n-1} = the weighted average annual rate of growth in the average cost of exchange resources in year n-1 as calculated on July 1 in year n. The average cost of exchange resources shall be based on the average system costs of C. P. National Corporation, Idaho Power Company, Montana Power Company, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light Company, and Utah Power & Light Company. If any of the seven utilities elect, pursuant to Section 10 of the Residential Purchase and Sale Agreement, to equalize rates in year n-1, the calculation of ARG shall not reflect the average system cost of such electing utility.

2. $\text{Rate} = \text{Rate}_{n-1} * 1.095$

where:

Rate_n = the rate in the operating year (July 1 - June 30) for which the SE-83 rate is being calculated; and

Rate_{n-1} = the SE-83 rate in the previous year (year n-1).

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the SE-83 rate is 98 percent Exchange and 2 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE NF-83

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Nonfirm Energy to be used both inside and outside the Pacific Northwest as well as outside the United States. This schedule also applies to energy delivered for emergency use under the conditions set forth in Section V.A of the General Rate Schedule Provisions. This rate schedule is not available for the purchase of energy which BPA has a firm obligation to supply except to the extent that short-term guarantees are agreed to, nor is this schedule applicable to contracts for which rates have been negotiated pursuant to section 7(l) of the Regional Act. This schedule supersedes Schedule NF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Market Rates

The price per kilowatthour of billing energy shall be set according to the following four rates. More than one rate may apply at any given time. However, BPA will not offer to schedule nonfirm energy at the Standard rate and Spill rate for delivery at the same time.

1. Standard Rate

The rate shall be 18.5 mills per kilowatthour.

The Standard rate shall apply when BPA does not implement the Spill rate.

2. Spill Rate

The rate shall be 11.0 mills per kilowatthour.

BPA may offer, at its discretion, to schedule nonfirm energy at the Spill rate instead of the Standard rate when one or more Federal Columbia River Power System (FCRPS) hydroelectric plants are spilling or are forecast to spill due to more FCRPS energy being available than can be sold at the Standard Rate.

3. Displacement Rate

The rate shall be:

a. 7.0 mills per kilowatthour for displacement of coal-fired resources and end-user alternate fuel sources.

b. 3.0 mills per kilowatthour for displacement of nuclear resources.

When all markets have been satisfied at the Standard or Spill rate, whichever is in effect, BPA may make additional energy available at the Displacement rate to displace coal-fired and nuclear resources and end-user alternate fuel sources. To qualify for the Displacement rate:

a. Coal-fired and nuclear resources must have Decremental Costs lower than the sum of the Standard rate or Spill rate, whichever is in effect, and 2.0 mills per kilowatthour.

b. End-user alternate fuel sources must have Decremental Costs lower than the sum of the Standard rate or Spill rate, whichever is in effect, and 4.0 mills per kilowatthour.

Decremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) which the purchaser is able to avoid by choosing not to produce the power being purchased at this rate.

When displacing coal-fired and nuclear resources, purchasers of energy at the Displacement rate must shut down or reduce the output of the identified displaceable resource. The output of such resource must be reduced in an amount equal to the amount of Displacement rate energy purchased. The purchaser must own and operate the identified resource or be able to control the generation level of the resource through purchase of the resource's variable output.

BPA may offer nonfirm energy for sale at the Displacement rate only to displace identified qualified resources and end-user alternate fuel sources.

4. Incremental Rate

The rate shall be equal to the Incremental Cost of power, described below, plus 2.0 mills per kilowatthour.

The Incremental Rate shall be applied to sales of power:

a. which is produced or purchased by BPA concurrently with the nonfirm sale;
b. which BPA may at its option not produce or purchase; and
c. which has an Incremental Cost greater than 16.5 mills per kilowatthour.

Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) which BPA would not have incurred if it had chosen not to produce or purchase the power being sold under this rate.

B. Contract Rate

For contracts that refer to this schedule to determine the value of energy, the rate is 13.9 mills per kilowatthour.

SECTION III. GUARANTEED DELIVERY

A surcharge of 1.8 mills per kilowatthour shall be applied for guaranteed delivery of nonfirm energy at the Standard rate, Spill rate, and Displacement rate except that no such surcharge shall be applied for guaranteed delivery of nonfirm energy at the Displacement rate for displacement of nuclear resources.

On the first and last working day of each week, or more often if BPA determines that it is appropriate, BPA will indicate the amounts of nonfirm energy available for delivery, normally for the next four days, on a guaranteed basis. On the first working day of each week BPA will indicate the daily or hourly amounts that it is willing to guarantee through at least the coming Friday. On the last working day of each week BPA will so indicate through at least the coming Tuesday. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy BPA plans to offer for sale on such days.

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

A. when BPA and the Purchaser mutually agree to increase or decrease the scheduled amounts; or

B. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation loss in the Pacific Northwest.

SECTION IV. DELIVERY:

BPA shall determine the availability of energy to be provided under this rate schedule and the associated rate of delivery.

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the NF-83 Standard Rate is 99.5 percent FBS and .5 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE EB-83

ENERGY BROKER RATE

SECTION I. AVAILABILITY:

This rate schedule may be applied to both sales and purchases of nonfirm energy among those participants in the Western Systems Coordinating Council (WSCC) Energy Broker System between whom agreements for energy transmission have been transacted. This schedule supersedes Schedule EB-1, which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

The following formula shall be used in determining the rate at which power will be sold or purchased on the energy broker:

$$\text{EB-83} = \frac{BP + SP}{2}$$

EB-83 =

where:

EB-83 = Energy Broker Rate
BP = Quoted Buy Price
SP = Quoted Sell Price

The Energy Broker will identify potential transactions when the Sell Price is at least 4.0 mills per kilowatthour less than the Buy Price. The final transaction rate for brokered nonfirm energy will be based on splitting the difference between the quoted Buy and Sell Prices, with the settlement for wheeling charges and energy losses defined in accordance with Exhibit A of the WSCC Broker Transmission Service Agreement.

When a transaction involving BPA takes place on the Energy Broker System, the BPA Buy Price and BPA Sell Price, respectively, shall be defined as follows:

A. The BPA Buy Price is the estimated decremental or equivalent expense per kilowatthour which would otherwise have been incurred by BPA in generating or purchasing power from alternative sources in lieu of broker energy scheduled for delivery to BPA during that hour.

B. The BPA Sell Price is the estimated incremental or equivalent expense per kilowatthour which would be incurred by BPA in supplying broker identified energy scheduled for delivery during such hour to the buyer from resources which are available to supply power during that hour as determined by BPA.

SECTION III. DELIVERY:

BPA shall determine the availability of energy to be provided under this rate schedule and the associated rate of delivery.

SECTION IV. RESOURCE COST CONTRIBUTION:

The cost contribution of different resource categories to the EB-83 rate is based upon the specific resource(s) offered during the scheduled time of sale.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION V. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SCHEDULE RP-83

RESERVE POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the purchase of:

A. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract;

B. power for which BPA determines no other rate schedule is applicable; and/or

C. power to serve a purchaser's firm power loads in circumstances where BPA does not have a power sales contract in force with such purchaser and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States.

This rate schedule supersedes Schedule RP-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Demand Charge

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $7.51 per kilowatt of billing demand;

2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.01 per kilowatt of billing demand;

3. all other hours: No demand charge.

B. Energy Charge

1. 34.3 mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.

2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand

1. Basic Service

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

2. Unauthorized Increase

That portion of any Measured Demand, as adjusted for power factor, which exceeds the Contract Demand during any billing month and which cannot be assigned:

a. to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or
b. to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

a. in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
b. as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Billing Energy

1. Basic Service

If applicable, the billing energy shall be the Contract Demand in kilowatthours as specified in the power sales contract. Otherwise the billing energy shall be the Measured Energy for the month.

2. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take pursuant to the power sales contract during that month and which cannot be assigned:

a. to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or
b. to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

a. in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or
b. as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

SECTION IV. POWER FACTOR ADJUSTMENT:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION:

The RP-83 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS

I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions
   - A. Approval of Rates
   - B. General Provisions
   - C. Reorganization of the Wholesale Power Rate Schedules and General Rate Schedule Provisions
     1. Reorganization of the Wholesale Power Rate Schedules
     2. Reorganization of the General Rate Schedule Provisions

II. Types of BPA Service
   - A. Priority Firm Power
   - B. New Resource Firm Power
   - C. Industrial Firm Power
   - D. Auxiliary Power
   - E. Firm Capacity
   - F. Surplus Firm Power
   - G. Surplus Firm Energy
   - H. Nonfirm Energy
   - I. Energy Broker Energy
   - J. Reserve Power

III. Billing Factors and Billing Adjustments
   - A. Billing Factors for Demand
     1. Measured Demand
     2. Contract Demand
     3. Computed Peak Requirement
     4. Computed Average Energy Requirement
     5. Computed Maximum Requirement
     6. Operating Demand
     7. Curtailed Demand
     8. Restricted Demand
     9. Auxiliary Demand
     10. Committed Demand
   - B. Billing Factors for Energy
     1. Measured Energy
     2. Computed Energy Maximum
     3. Committed Energy
   - C. Billing Adjustments
     1. Power Factor Adjustment
     2. Exchange Adjustment Clause
     3. Supply System Adjustment Clause
     4. Conservation Charge

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS (Continued)

IV. Other Definitions
- A. Restriction of Deliveries
- B. Computed Requirements Purchasers
  - 1. Designation as a Computed Requirements Purchaser
  - 2. Purpose of the Computed Requirements Designation
  - 3. Definitions and Terms Relating to Computed Requirements Purchasers with Power Sales Contracts Executed Prior to December 5, 1980
    - a. General Principles
    - b. Determination of Assured Capability

V. Application of Rates Under Special Circumstances
- A. Energy Supplied for Emergency Use
- B. Construction, Test and Start-up, and Station Service
- C. Application of Rates During Initial Operation Period
- D. Application of the Industrial Incentive Rate
- E. Temporary Curtailment of Contract Demand

VI. Billing Information
- A. Billing for Purchasers with More than One Point of Delivery
- B. Determination of Estimated Billing Data
- C. Billing Month
- D. Payment of Bills

GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS:

A. Approval of Rates

Schedules of rates and charges for electric power sold by BPA or modifications to those schedules shall become effective on an interim or final basis after confirmation and approval by the Federal Energy Regulatory Commission in accordance with procedures established by the Commission.

B. General Provisions

BPA's Wholesale Power Rate Schedules and associated General Rate Schedule Provisions (GRSP's) which are effective November 1, 1983, supersede in their entirety BPA's Wholesale Power Rate Schedules and GRSP's effective October 1, 1982. The revised schedules and provisions shall be applicable to every BPA contract, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act).

C. Reorganization of the Wholesale Power Rates and General Rate Schedule Provisions

1. Reorganization of the Wholesale Power Rates

All references in the industrial power sales contract to Section 4 of the rate schedules for Industrial Firm Power shall be deemed to refer to the section in such schedules entitled "Billing Factors."

2. Reorganization of the General Rate Schedule Provisions (GRSP's)

All references to sections in those GRSP's which were in effect prior to November 1, 1983, are deemed to refer to the section in these revised GRSP's indicated in the listing below.

Section Title	Old GRSP's Section #	New GRSP's Section #
Priority and New Resource Firm Power	1.1	II.A
(Now divided into two sections)		II.B
Modified Firm Power	1.2	N/A
Firm Capacity	1.3	II.E
Industrial Firm Power	1.4	II.C
Authorized Increase	1.5	N/A
Firm Energy	1.6	N/A
Contract Demand	2.1	III.A.2
Auxiliary Demand	2.2	III.A.9
Measured Demand	2.3	III.A.1
Peak Computed Demand and Energy Computed Demand	2.4	III.A.3
(Now divided into 3 sections: Computed Peak		III.A.4
Requirement, Computed Average Energy Requirement,		III.A.5
and Computed Maximum Requirement)		
Restricted Demand	2.5	III.A.8
Curtailed Demand	2.6	III.A.7
Temporary Curtailment of Contract Demand	3.1	V.E
Energy Supplied for Emergency Use	4.1	V.A
Application of Rates During Initial Operation Period	5.1	V.C
Billing	6.1	VI.A
Determination of Estimated Billing Data	6.2	VI.B
Billing Month	7.1	VI.C
Payment of Bills	8.1	VI.D
Average Power Factor	9.1	III.C.1
Approval of Rates	10.1	I.A
General Provisions	11.1	I.B

SECTION II. TYPES OF BPA SERVICE:

A. Priority Firm Power

Priority Firm Power is electric power which BPA will make continuously available for resale, direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies.

Construction, test and start-up, and station service are defined in section V.B of these GRSP's.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) may purchase Priority Firm Power pursuant to the Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm Rate for determining the amount of power to be exchanged.

Power purchased under the Priority Firm Power Rate Schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSP's (section IV.A). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSP's.

Any increase in energy consumption of a load as defined in:

1. section 3.(13) of the Regional Act, or
2. section 8 of any BPA utility power sales contract executed after December 5, 1980,

shall be served under the New Resource Firm Power Rate.

B. New Resource Firm Power

New Resource Firm Power is electric power which BPA will make continuously available:

1. for any new large single load as defined in section 3.(13) of the Regional Act, and as described in section 8 of any BPA utility power sales contract executed after December 5, 1980,

2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and/or

3. for construction, test and start-up, and station service for facilities owned and/or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSP's (section IV.A). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSP's.

C. Industrial Firm Power

Industrial Firm Power is electric power which BPA will make continuously available to a direct-service industrial purchaser on a Contract Demand basis subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and

2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

When such a restriction is made necessary, BPA shall restrict the direct-service industrial purchaser's Operating Demand for Industrial Firm Power to the extent necessary to prevent, if possible, and otherwise to minimize restriction of Priority Firm and New Resource Firm Power.

D. Auxiliary Power

Auxiliary Power is that power which a direct service industrial purchaser requests and which BPA agrees to make available to serve that portion of the purchaser's load which is in excess of the purchaser's Operating Demand for Industrial Firm Power.

E. Firm Capacity

Firm Capacity means capacity which BPA assures a purchaser will be available in the amounts and during the periods specified in the contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

F. Surplus Firm Power

Surplus Firm Power is power which BPA assures a purchaser will be available during the period or periods specified in the contract. Such power may be purchased for resale or direct consumption by entities both inside and outside the United States. Surplus Firm Power may, however, be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

G. Surplus Firm Energy

Surplus Firm Energy is energy which BPA assures a purchaser will be available during the period or periods specified in the contract. Such energy may be purchased for resale or direct consumption by entities both inside and outside the United States. Surplus Firm Energy may, however, be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

H. Nonfirm Energy

Nonfirm Energy is energy which BPA supplies or makes available to a purchaser under an arrangement which does not have the guaranteed continuous availability feature of firm power. However, Nonfirm Energy which has been purchased under the guarantee provision in the Nonfirm Energy Rate Schedule shall be provided to the purchaser in accordance with the provisions of that schedule. Nonfirm Energy may not be used to serve any load which BPA has a firm obligation to supply.

I. Energy Broker Energy

Energy Broker Energy, as used in BPA's EB-83 rate schedule, is Nonfirm Energy that:

1. BPA purchases from the Western Systems Coordinating Council (WSCC) Energy Broker System under the Energy Broker Rate Schedule, or

2. BPA makes available to the WSCC for sale to WSCC participants. Power that BPA sells to WSCC participants is subject to the Restriction of Deliveries section of these GRSP's (section IV.A).

J. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. to meet the purchaser's unanticipated load growth,

2. to provide service when no other type of power is deemed applicable, and/or

3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSP's (section IV.A).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. BILLING FACTORS FOR DEMAND

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section unless the terms of a power sales contract executed after December 5, 1980, provide otherwise. Measured Demand shall be that portion of the metered and/or scheduled demand which is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand and/or the scheduled demand, as hereinafter defined. The Measured Demand for each point of delivery shall be determined either on a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

Metered Demand:

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

a. at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,
b. during each time period specified in the applicable rate schedule, and
c. during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.B herein. In determining the metered demand, BPA will exclude any abnormal integrated demands due to or resulting from:

a. emergencies or breakdowns on, or maintenance of, the Federal system facilities, and
b. emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

Scheduled Demand:

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

a. to each system for which scheduled demand is the basis for determination of the Measured Demand,
b. during each time period specified in the applicable rate schedule, and
c. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Contract Demand

The Contract Demand shall be the maximum number of kilowatts or kilowatthours that the purchaser (utility, DSI, or other entity) agrees to purchase and BPA agrees to make available. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries.

3. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements under power sales contracts executed after December 5, 1980, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers,
b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers, and
c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

For computed requirements purchasers with power sales contracts executed prior to December 5, 1980, the purchaser's Computed Peak Requirement for each billing month shall be the largest amount during such month by which the purchaser's actual hourly system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, as determined pursuant to section IV.B.3 of these General Rate Schedule Provisions.

4. Computed Average Energy Requirement

For computed requirements purchasers with power sales contracts executed after December 5, 1980, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers,
b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers, and
c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

For computed requirements purchasers with power sales contracts executed prior to December 5, 1980, the purchaser's Computed Average Energy Requirement for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability, as determined pursuant to section IV.B.3 of these General Rate Schedule Provisions.

5. Computed Maximum Requirement

The Computed Maximum Requirement is the larger of the Computed Peak Requirement and the Computed Average Energy Requirement.

6. Operating Demand

The Operating Demand is that demand which is established in accordance with section 5(b) of the purchaser's power sales contract. For the purpose of the rate schedules and these GRSP's two other terms are defined: the Forecasted Operating Demand and the Monthly Operating Demand.

Forecasted Operating Demand:

The Forecasted Operating Demand for each direct-service industrial purchaser is that demand which was forecast for the development of rates. Those Forecasted Operating Demands are presented below for Period A (November 1, 1983, through June 30, 1984), Period B (July 1, 1984, through June 30, 1985), and Period C (July 1, 1985 until the next Rate Adjustment Date).

		PERIOD A	PERIODS B & C
a.	Aluminum Company of America	478.0 MW	469.0 MW
b.	Arco Metals Company	227.0 MW	249.0 MW
c.	The Carborundum Company	0.6 MW	0.6 MW
d.	Crown Zellerbach Corporation	16.7 MW	16.7 MW
e.	Elkem Metals Company	0.0 MW	0.0 MW
f.	Georgia-Pacific Corporation	25.9 MW	27.8 MW
g.	Intalco Aluminum Company	452.0 MW	452.0 MW
h.	Kaiser Aluminum & Chemical Corporation	426.0 MW	516.0 MW
9.	Martin Marietta Aluminum, Inc.	424.0 MW	412.0 MW
i.	Oregon Metallurgical Corporation	7.0 MW	7.0 MW
j.	Pacific Carbide and Alloys Company	6.7 MW	6.7 MW
k.	Pennwalt Corporation	62.0 MW	62.0 MW
1.	Reynolds Metals Company	580.0 MW	603.0 MW

Monthly Operating Demand:

The Monthly Operating Demand is used to compute the amount of the customer charge for each of BPA's direct-service industrial customers purchasing under the IP-83 Rate Schedule. The Monthly Operating Demand shall be determined by each purchaser and shall be submitted to BPA by November 1, 1983, for Period A, by July 1, 1984, for Period B, and by July 1, 1985, for Period C, if applicable. The purchaser shall determine its Monthly Operating Demand for each month of the rate period (Period A, Period B, and Period C) such that the average of the Monthly Operating Demands for each rate period shall equal the Forecasted Operating Demand for the period. The Monthly Operating Demand may not exceed, at any time, the purchaser's Operating Demand as specified in the power sales contract. If a purchaser does not make a submission to BPA, BPA shall assume that the purchaser will take its Forecasted Operating Demand in each month of the rate period.

7. Curtailed Demand

A Curtailed Demand shall be the number of kilowatts of Industrial Firm Power which results from the purchaser's request for such power in amounts less than the Operating Demand therefor. Each purchaser of Industrial Firm Power may curtail its demand in accordance with the terms of its power sales contract.

8. Restricted Demand

A Restricted Demand shall be the number of kilowatts of Industrial Firm Power which results when BPA has restricted delivery of such power for one (1) clock-hour or more. BPA shall make such restrictions in accordance with the terms of the purchaser's power sales contract.

Such Restricted Demand shall be determined by BPA after the purchaser has made its determination whether to accept such restriction or, instead, to curtail its demand for the month.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve the purchaser's load during the period specified in the purchaser's request. The purchaser may request up to three levels of Auxiliary Demand during a billing month. If BPA agrees to such request but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power shall be deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the purchaser in accordance with the provisions of Section 9(a) of the purchaser's power sales contract.

10. Committed Demand

Committed Demand is the number of kilowatts of Industrial Firm Power which a customer agrees to purchase on a take-or-pay basis under the Industrial Incentive Rate. The Committed Demand shall be established by written agreement with each industrial customer electing to purchase on this basis. A purchaser may specify up to three (3) levels of Committed Demand for each billing month.

B. BILLING FACTORS FOR ENERGY

1. Measured Energy

The purchaser's Measured Energy shall be determined in the manner described in this section unless the terms of a power sales contract executed after December 5, 1980, provide otherwise. Measured Energy shall be that portion of the metered and/or scheduled energy which is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy and/or the scheduled energy, as hereinafter defined.

Metered Energy:

The metered energy for a purchaser shall be the number of kilowatthours which are recorded on the kilowatthour meter, adjusted as specified in the power sales contract, and delivered to a purchaser:

a. at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and
b. during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.B herein.

Scheduled Energy:

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

a. for each system for which scheduled energy is the basis for determination of the Measured Energy, and
b. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Committed Energy

Committed Energy is the number of kilowatthours of Industrial Firm Power which a purchaser agrees to purchase on a take-or-pay basis under the Industrial Incentive Rate. The Committed Energy shall be established by written agreement with each industrial customer electing to purchase on this basis. In lieu of providing a kilowatthour figure, a customer may contractually specify the load factor at which the power will be purchased.

C. BILLING ADJUSTMENTS

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or
b. are provided under more than one rate schedule

and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a poor power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Exchange Adjustment Clause

To the extent that the accounting net cost of exchange resources (the cost of the exchange resources to BPA minus the revenue collected from the exchange loads) differs from that forecast for development of rates, a rebate shall be given or a surcharge assessed to all those purchasing under rate schedules which include this adjustment (PF-83, IP-83, CF-83, and NR-83).

There will be an Exchange Adjustment for the period November 1, 1983, through June 30, 1984 (Period A), another such adjustment for the period July 1, 1984, through June 30, 1985 (Period B), and a third adjustment for the period July 1, 1985, until the next Rate Adjustment Date (Period C), provided BPA does not adjust its wholesale power rates on July 1, 1985.

Calculation and Application of the Exchange Adjustment:

The total amount of revenue which must be rebated or recovered in order for BPA to adjust for changes in the accounting net cost of the exchange shall be calculated for each exchange adjustment period according to the formula below. However, because the exchange adjustment is not being applied to the Surplus Firm Power Rate Schedule to which exchange costs have been allocated, the actual amount of revenue rebated or recovered will be less than the value of TAR.

$$TAR = (AEC - AER) - (FEC - FER)$$

where:

TAR = total amount of revenue underrecovery (or overrecovery) of the accounting net cost of the exchange for the exchange adjustment period;

AEC = actual total exchange cost for the period for which the exchange adjustment is being made; AEC includes exchange costs from the utilities whose average system cost (ASC) is deemed equal to the Priority Firm Power Rate (deeming utilities);

AER = actual exchange revenue for the relevant period; both AEC and AER will be calculated without considering the effect of the Exchange Adjustment Clause, but including the effect of the Supply System Adjustment Clause; AER includes exchange revenue from deeming utilities;

FEC = forecasted exchange cost;
for Period A, the value of FEC is equal to $6,346,096;
for Period B, the value of FEC is equal to $10,886,898;
for Period C, the value of FEC shall be calculated after BPA has determined the number of months in Period C;

FER = forecasted exchange revenue;
for Period A, the value of FER is equal to $5,369,005;
for Period B, the value of FER is equal to $8,092,008;
for Period C, the value of FER shall be calculated after BPA has determined the number of months in Period C;

Next, the rebate or surcharge for each customer class for each period shall be calculated.

$$CCEA = TAR * ECP$$

where:

CCEA = rebate or surcharge for each customer class for each exchange adjustment period; two values of CCEA shall be calculated for Firm Capacity service, one value for contract year and general Firm Capacity service and another for contract season service.

ECP = exchange cost percentage for the customer class, calculated by dividing the exchange costs assigned to the class of service by the total forecasted exchange costs; the value of "ECP" is provided in the rate schedule for each class of service subject to the Exchange Adjustment Clause; different values are given in the Firm Capacity Rate Schedule for the different types of Firm Capacity service.

BPA shall apply the following formula in order to calculate the exchange adjustment for an individual customer:

$$ICEA = \frac{(CCEA * ICB)}{SCB} * [1 + \frac{(INT * MO)}{24}]$$

where:

ICEA = individual customer's exchange adjustment (in dollars) for the exchange adjustment period;

ICB = sum of the individual customer's bills (in dollars and net of the LDD) associated with a given ECP for the class of power in question during the exchange adjustment period; ICB shall exclude purchases under the Industrial Incentive Rate;

SCB = sum of all the customer's bills (in dollars and net of the LDD) associated with a given ECP for the class of power in question during the exchange adjustment period; the computation of SCB for the Industrial Firm Power Rate (IP-83) shall exclude purchases under the Industrial Incentive Rate;

INT = average interest rate charged to BPA by the U.S. Treasury during the exchange adjustment period.

MO = number of months in the rate period.

No exchange adjustment will be made to any rate schedule if:

$\frac{CCEA}{SCB}$ is less than .01 for that rate class.

The rebate or surcharge shall be calculated as soon after:

a. July 1, 1984, for Period A,
b. July 1, 1985, for Period B, and
c. the end of Period C,

as possible. BPA shall notify affected purchasers of the impending adjustment as soon as the amount of the adjustment has been calculated. Payment of the adjustment (either the rebate or the surcharge) shall be made within 30 days of the date on the adjustment notice provided to the purchaser. Late payment shall be subject to late payment charges as described in section VI.D of these GRSP's. The Due Date, as defined in section VI.D, for the Exchange Adjustment shall be 30 days from the date on the adjustment notice.

Provisions for Final Adjustment:

Approximately one year from the end of each exchange adjustment period, BPA shall recalculate the exchange adjustment rebate or surcharge for each customer. The recalculation shall be based on the most up-to-date values of the variables used in the adjustment formula. This recalculation shall be final and not subject to later modification, except pursuant to orders of FERC or the United States Court of Appeals for the Ninth Circuit.

BPA shall calculate the difference between the amount of the initial adjustment and the final adjustment. That difference shall be subject to an interest charge for the period commencing 30 days from the date on the initial adjustment notice and ending on the date of the final adjustment notice. The interest rate used in the computation of the interest charge shall be the average interest rate charged to BPA by the U.S. Treasury for the period in question.

BPA shall then notify affected customers of the amount to be rebated or surchargeed. Payment shall be made within 30 days of the date on the adjustment notice provided to the purchaser. Late payment shall be subject to late payment charges as described in section VI.D of these GRSP's. The Due Date, as defined in section VI.D, for the Exchange Adjustment shall be 30 days from the date on the adjustment notice.

Where necessary, BPA shall later modify the recalculation to reflect any changes in average system cost determination ordered by FERC or the United States Court of Appeals for the Ninth Circuit. In making such additional adjustment, BPA shall adhere to the procedures outlined above.

3. <u>Supply System Adjustment Clause</u>

Beginning July 1, 1984, an adjustment shall be made to the charges in those rate schedules which include the Supply System Adjustment. The Supply System Adjustment Clause adjusts for differences between the total cost of Supply System ownership shares of Plants 1, 2, and 3 and the cost forecast used in the development of the rates.

Calculation of the Supply System Adjustment:

The adjustment for each rate schedule shall be calculated as follows:

$$\frac{SS * \quad [(ACT - \$548,933,000) + (BUD - \$770,125,000)]}{BD}$$

where:

SS = the percentage of total Supply System costs allocated to the class of service in the Cost of Service Analysis for operating year 1985; the value for "SS" is provided in the rate schedule for the class of service in question;

ACT = two-thirds of the Net Funding Requirements (in thousand of dollars) in the Supply System Annual Budget or amendment thereto for operating year (OY) 1984 as of May 1, 1984;

BUD = the Net Funding Requirements (in thousand of dollars) in the Supply System Annual Budget for OY 1985, as of May 1, 1984;

BD = for the Priority Firm Power Rate Schedule, PF-83, the sum of the winter and summer energy billing determinants (in gigawatthours) for Priority Firm service as forecasted in the Wholesale Power Rate Design Study; for the CF-83 Firm Capacity Rate Schedule, the sum of the winter and summer generation capacity billing determinants (in megawattmonths); the value of "BD" is provided in the rate schedule for each class of service subject to the Supply System Adjustment Clause;

Should BPA become liable for payment of additional funds loaned to BPA or another organization created for the purpose of funding construction of Supply System projects 1, 2, or 3, the costs to BPA associated with repayment of such funds will be included in ACT and BUD.

Insofar as any cost resulting from a resumption of construction of Supply System Plants 1 and/or 3 is reflected in the Net Funding Requirements or BPA's financial obligations, except as described below, the increase in cost caused by such resumption of construction shall be excluded from the determination of "ACT" and "BUD". However, if the exclusion of the cost increase caused by such a resumption in construction of Supply System Plants 1 and/or 3 would result in a negative adjustment, then the adjustment shall be the lesser of:

a. the adjustment calculated without excluding such costs from ACT and BUD, or
b. zero.

No Supply System Adjustment shall be made if:

$$\frac{[(ACT - \$548,933,000) + (BUD - \$770,125,000)]}{\$1,319,058,000} \text{ is less than } .01$$

Implementation of the Supply System Adjustment:

As soon after May 1, 1984, as possible, BPA shall identify:

1. the difference between two-thirds of the actual OY 1984 Supply System costs and $548,933,000, and/or
2. the difference between the OY 1985 Supply System Annual Budget, as revised or amended, and $770,125,000.

BPA shall notify interested parties of BPA's initial findings concerning the changes in Supply System costs and the unit adjustment caused by those changes. In the notice, BPA shall request written comments regarding its findings. By May 18, 1984, BPA shall file written testimony with interested parties, explaining how BPA arrived at its initial findings and how the proposed adjustment was calculated. Parties wishing to file written testimony have until close of business on May 25, 1984, to submit their testimony to BPA. Interested parties shall be afforded a reasonable opportunity to examine the testimony of all witnesses. Written comments on the calculation of the proposed Supply System Adjustment will be accepted until close of business on June 1, 1984. BPA shall then evaluate all comments received. Comments and testimony should be directed to the proper calculation of the adjustment, not the appropriateness of the level of Supply System budgets or construction schedules. Consideration of comments and more current information, i.e., the Supply System Annual Budget for OY 1985 as of June 15, 1984, may result in the final adjustment differing from the proposed adjustment. Prior to implementing the adjustment, BPA shall notify all affected parties of the amount of the final adjustment.

4. Conservation Charge

BPA shall assess a charge on all purchasers who are party to any of BPA's conservation contracts which contain the conservation charge provision. That charge, established pursuant to section 32 of the General Conservation Contract Provisions (GCCP's), shall be assessed for each billing period. For these conservation charges, the billing periods shall be:

Period A: November 1, 1983, through June 30, 1984;
Period B: July 1, 1984, through June 30, 1985; and
Period C: July 1, 1985, until the next Rate Adjustment Date. Period C shall only occur if BPA does not adjust its wholesale power rates on July 1, 1985.

For metered requirements customers the charge shall be equal to:

COST * ACTLD

where:

COST = the cost in mills per kilowatthour for each conservation charge period; COST is equal to:

.179 for Period A; and
.370 for Periods B and C;

ACTLD = for Periods A and B, the actual non-BPA load for the operating year (July 1 through June 30) for each utility being assessed this charge; for Period C, the utility's actual non-BPA load in the months which constitute Period C; non-BPA load is defined below;

For computed requirements customers (including the investor-owned utilities) the charge shall be equal to:

(COST * ACTLD) + [(ACTLD / UTTL) * PAYMT * FACTOR]

i.e., Load Charge + Reimbursement Charge where:

COST	=	the cost in mills per kilowatthour for each conservation charge period; COST is equal to: .143 for Period A; and .248 for Periods B and C.
ACTLD	=	for Periods A and B, the actual non-BPA load for the operating year (July 1 through June 30) for each utility being assessed this charge; for Period C, the utility's actual non-BPA load in the months which constitute Period C; non-BPA load is defined below;
UTTL	=	the utility's actual total load for the operating year for Periods A and B; for Period C, the utility's actual total load in the months which constitute Period C;
PAYMT	=	direct payments (by BPA, a trustee, or other disbursing agent to a utility, its contractor, or its assignee) of funds budgeted to implement the Street and Area Lighting Program Agreement and/or the Residential Weatherization Conservation Program Agreement; PAYMT is a cumulative figure and shall be equal to the sum of those payments, or applicable portions thereof, obligated for the period November 1, 1983, through the end of the contract charge period in question;
FACTOR	=	the amount of money to be collected from the Reimbursement Charge (as opposed to the Load Charge) for computed requirements purchasers, divided by the forecasted conservation acquisition expenditures for the computed requirements customers' non-BPA load; FACTOR is equal to: .068 for Period A; and .088 for Periods B and C.

Loads shall be determined according to the following formulas:

NON-BPA LOAD = SALES + LOSSES - REQMTS

and

TOTAL LOAD = SALES + LOSSES + EXCHANGE

where:

SALES	=	Retail sales of the utility for the operating year; (Total sales for the utility excluding sales for resale;)
LOSSES	=	Losses relating to the retail sales of the utility for the operating year. Losses shall be equal to the system losses reported by the utility, or if system losses are not available, losses shall be calculated by multiplying the retail sales figure by 5.0 percent;

REQMTS	=	Firm power purchases from BPA for the utility under the Priority Firm Power Rate for the operating year; REQMTS excludes purchases under the Residential Purchase and Sale Agreements;
EXCHANGE	=	Exchange purchases under the Residential Purchase and Sale Agreement for the utility for the operating year.

The procedure for submitting load information to BPA shall be specified by BPA prior to June 30, 1984. For metered requirements customers whose BPA power bills are net of contractually agreed-upon resources, BPA will accept an an approximation for the non-BPA load specified in the formula. That approximation shall be equal to the output of those contractually agreed-upon resources which are used to meet loads in the operating year.

BPA shall issue an estimated bill for the conservation contract charge, to be followed by a final bill. The estimated bill shall be based on BPA's projections of ACTLD, UTTL, and PAYMT. Issuance and payment of this estimated bill shall be according to the payment provisions of the GCCP's.

The final bill shall be computed after receipt and verification of the actual load information from the utility customers. The final bill shall be based on ACTLD, UTTL, and PAYMT, as defined above. BPA shall calculate the difference between the amount of the initial contract charge and the final contract charge. That difference shall be subject to interest for the intervening period. The interest rate used in the computation of the interest charge shall be based on the average interest rate charged to BPA by the U.S. Treasury for the period in question. Payment of the adjustment (either the rebate or the surcharge) shall be made within 30 days of the date on the adjustment notice provided to the purchaser. Late payment shall be subject to late payment charges as described in section VI.D of these GRSP's. The Due Date, as defined in section VI.D, for the Conservation Charge shall be 30 days from the date on the adjustment notice.

SECTION IV. OTHER DEFINITIONS:

A. Restriction of Deliveries

Deliveries of capacity and/or energy to any purchaser may be restricted when operation of the facilities used by BPA to service such purchaser is:

1. suspended,
2. interrupted,
3. interfered with,
4. curtailed, or
5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

B. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if:

a. it is so designated in its power sales contract executed after December 5, 1980, or
b. if it has one or more potential abilities as described in paragraphs (1) and (2) below:

(1) Such purchaser has generation of its own which can be sold in such a way as to increase BPA's obligation to deliver firm power to that purchaser because of such sale or,
(2) such purchaser has the ability to redistribute generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal system.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract for all computed requirements purchasers with power sales contracts executed after December 5, 1980.

For computed requirements purchasers with power sales contracts executed before December 5, 1980, the amount of capacity and energy required for normal and prudent operations is that which would be sufficient to meet the load and provide adequate reserves through the most critical water or other conditions which might reasonably be expected to occur. Purchase on a computed requirements basis for a purchaser with a power sales contract executed before December 5, 1980, depends on the relationship of the purchaser's resource capability to the purchaser's system requirements. Thus, the billing factors to be applied to such a computed requirements purchaser for any month cannot be determined until after the end of the month. As each such purchaser must estimate its own load and is in the best position to follow that load from day to day, it is the purchaser's responsibility to request scheduling of power from BPA.

3. <u>Definitions and Terms Relating to Computed Requirements Purchasers with Power Sales Contracts Executed Prior to December 5, 1980</u>

Those purchasers whose power sales contracts were executed prior to December 5, 1980, and who are designated as computed requirements purchasers based on the abilities listed in section IV.B.1.b, above, shall be governed by the terms of this subsection.

a. <u>General Principles</u>:

(1) The assured peaking capability and assured average energy capability of each of the purchaser's systems shall be determined and applied separately.

(2) As used in this section, "year" or "operating year" shall mean the 12-month period commencing July 1.

(3) The critical period is that period, described below, during which the purchaser would have the maximum requirement for peaking or energy from BPA. That period would be determined for the purchaser's system under adverse streamflow conditions and adjusted for:

(a) current water uses,
(b) assured storage operation, and
(c) appropriate operating agreements.

In determining the maximum requirement for peaking or energy from BPA, the firm capability of all resources available to the purchaser shall be utilized in such a manner as to place the least requirement on BPA.

(4) Critical water conditions are those conditions of streamflow in the operating year or years which would result in the minimum capability of the purchaser's firm resources during the critical period. Those conditions of streamflow are based on historical records as adjusted for:

(a) current water uses,
(b) assured storage operation, and
(c) appropriate operating agreements.

(5) Prior to the beginning of each operating year, the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on BPA. Such assured capability shall be effective after review and approval by BPA.

(6) The purchaser's assured average energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on BPA within each year of the critical period. The requirement placed on BPA may increase each year, but by no more than the sum of:

(a) the purchaser's annual load growth and
(b) any reductions in assured average energy capability caused by retirement or loss of one of the purchaser's firm resources.

(7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver to its load on a firm basis. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to BPA. BPA may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if BPA determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

(8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability

The purchaser's assured peaking and assured energy capabilities shall be the respective sums of:

(1) the capabilities of its hydroelectric generating plants based on the most critical water conditions experienced to date on the purchaser's system,

(2) the capabilities of its thermal generating plants based on such adverse fuel or other conditions which might reasonably be expected to occur, and

(3) the firm capabilities of other resources made available to the purchaser under contracts executed prior to the beginning of the operating year. The firm capabilities of these acquired resources will be based on the capabilities after adjustment for reserves.

Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) Hydroelectric Generating Facilities

The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the conditions necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that, when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy requirement on BPA for a period of one (1) month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify BPA in writing of the assured average energy capability to be applied tentatively to the preceding month. Such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured average energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured average energy capability to be applied to the preceding month, provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured average energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by BPA, shall demonstrate by a suitable regulation study based on critical water conditions:

(a) that such change could actually be accomplished, and
(b) that the remaining balance of its total critical period assured average energy capability could be developed without adversely affecting the firm capability of other purchaser's resources.

The algebraic sum of all such changes in the purchaser's assured average energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation as indicated by revisions in the monthly distribution of critical period energy capability.

(2) Thermal Generating Facilities

The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such peaking and average energy capabilities shall be based on those adverse fuel or other conditions that might reasonably be expected to occur. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time, should any such situation arise.

(3) Other Sources of Power

The peaking and average energy assured capability of other firm resources available under contracts to the purchaser shall be determined prior to each operating year.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES:

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm and/or New Resource Firm Power shall pay in accordance with the Nonfirm Energy Rate Schedule, NF-83, and Emergency Capacity Rate Schedule, CE-83, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or
2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefor settled under exchange agreements.

B. Construction, Test and Start-up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates during Initial Operation Period

For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

1. direct-service industrial purchasers having new, additional, or reactivated plant facilities, and
2. utility purchasers serving such an industrial purchaser with power purchased from BPA.

If the purchaser requests billing on a Measured Demand basis pursuant to section 4 of a direct-service industrial power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the daily Measured Demands as adjusted for power factor. However, at no time during the period of restoration, as defined in section 4(e) of such power sales contract, shall the daily billing demand be lower than any previous daily billing demand during such period. Should the Measured Demand for any day during the period of restoration be lower than the daily billing demand for the previous day, the previous day's daily billing demand shall be used as the daily billing demand for such day.

Any rate schedule provisions regarding Contract Demand, billing demand, and minimum monthly charges which are inconsistent with this section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by BPA, be extended beyond the initial 3-month period for such additional time as is justified by the developmental character of the operations.

D. Application of the Industrial Incentive Rate

The Industrial Incentive Rate shall apply solely to the purchasers of Industrial Firm Power under the IP-83 wholesale power rate. The Industrial Incentive Rate is elective for the customer.

Determination of the Rate Level:

BPA shall determine when and if the Industrial Incentive Rate shall be offered to purchasers of Industrial Firm Power. In order to make that determination, BPA shall use the following procedure:

a. BPA shall conduct a study to determine if total BPA revenue would increase as a result of implementation of the Industrial Incentive Rate. If revenues from the Industrial Incentive Rate minus foregone surplus firm and nonfirm revenues are greater than the revenues from anticipated sales to the DSI's at the Standard Industrial Rate, the Industrial Incentive Rate will be offered to purchasers of Industrial Firm Power. BPA shall initiate such a study if BPA believes that adoption of the Industrial Incentive Rate would be appropriate. In addition, BPA may (but is not obligated to) conduct a study in response to a customer's request.

b. To conduct the study, BPA shall determine the period of time for which the Industrial Incentive Rate would be effective. Such period shall be for no more than 12 months and no less than 6 months or the end of the rate period, whichever comes first.

c. Prior to BPA's offering an Industrial Incentive Rate, BPA and all interested DSI customers shall negotiate and execute a generic contract regarding the sale of Industrial Firm Power under the Industrial Incentive Rate. The information specified in (1), (2), and (3), below, shall be specified in an exhibit to the contract. Because this information will not be available until an incentive rate is adopted, this exhibit shall be attached to the contract only after BPA adopts an incentive rate:

   (1) the demand and energy charges for the Industrial Incentive Rate,
   (2) the Committed Demand and Committed Energy for each direct-service industrial customer electing to purchase under the Industrial Incentive Rate, and
   (3) the time period for which the rate is to be effective.

d. Using the Nonfirm Revenue Analysis Program, a DSI load forecasting model similar to the model used in the rate case (a model that considers the production process for each aluminum plant and includes a forecast of the price of aluminum), and BPA's forecast of surplus firm sales, BPA shall determine the DSI rate which maximizes total BPA revenues, taking into account the sensitivity of the revenue to small changes in assumptions.

e. If the rate resulting from the study is less than the Standard Industrial Rate, BPA shall notify its customers that BPA is proposing to implement the resulting rate as the Industrial Incentive Rate. If adopted, the rate will be in effect for the time period specified in the notice. BPA shall also make the supporting study available to interested customers.

f. BPA shall accept comments on the proposed rate and the supporting study for a period of no less than 3 weeks (21 days) from the date of the notice to the customers.

g. BPA shall evaluate the comments on the proposed rate and the supporting study and shall make that evaluation available to interested parties. BPA shall indicate in its evaluation whether the record supports implementation of the proposed Industrial Incentive Rate and, if so, the level of the proposed incentive rate. (The comments may affect the results of the study, so the level of the proposed Industrial Incentive Rate may change.)

h. If the record supports implementation of an incentive rate, BPA shall solicit, from each DSI, its Committed Demand and Committed Energy at the rate determined in steps d-g, above. In the solicitation, BPA shall notify the DSI's of the period of time for which the Industrial Incentive Rate is proposed to be effective. Based upon the results of the solicitiation, BPA shall revise its studies of forecasted revenues and adopt the Industrial Incentive Rate if that revision still shows that such adoption results in greater total BPA revenues than are forecast to be received under the Standard Industrial Power Rate. The DSI response to the solicitation shall be contractually binding, and the response shall be attached to the generic contract upon adoption of the proposed Industrial Incentive Rate.

Rate Structure:

The Industrial Incentive Rate shall include a customer charge as well as demand and energy charges net of the value of reserves credit. The charges shall be equal to a uniform percentage of the Standard Industrial Rate demand and energy charges, also net of the value of reserves credit.

E. Temporary Curtailment of Contract Demand

The reduction of charges for power curtailed pursuant to the purchaser's power sales contract and section II.C hereof shall be applied in a uniform manner.

SECTION VI. BILLING INFORMATION:

A. Billing for Purchasers with More than One Point of Delivery

Purchasers shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule or schedules unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purposes of these rate schedules and GRSP's, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's noncoincidentally billed points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery.

When the contract provides for billing on a coincidental demand basis, a charge shall be assessed for the diversity among the purchaser's coincidentally billed points of delivery unless BPA elects to waive such charge in whole or in part. The purpose of charging the customer for diversity is to compensate BPA for lost revenue due to coincidentally combining demands from multiple points of delivery. BPA may calculate the charge by applying an existing methodology or by specifying a diversity factor in the power sales contract.

Diversity factors will be specified in the power sales contract for coincidentally-billed points of delivery of customers who are not currently assessed a diversity charge and who, by BPA's criteria, should be assessed the charge. Any changes to existing diversity charges shall be likewise reflected in the power sales contract. The diversity factor(s) specified in the power sales contract shall be multiplied by the respective coincidental demands for the coincidentally-billed points of delivery in order to determine the billing demand for those points of delivery.

The diversity factor(s) specified in the power sales contract shall be no greater than:

$$1 + \frac{\text{Noncoincidental Demand} - \text{Coincidental Demand}}{\text{Coincidental Demand}}$$

where the Noncoincidental and Coincidental Demands used in the calculation are the sum of the monthly demands for 12 months prior to the computation of the charge for each of the purchaser's coincidentally-billed points of delivery. BPA shall revise the contractually-specified diversity factor(s) in accordance with the terms of the power sales contract.

B. Determination of Estimated Billing Data

If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

C. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

D. Payment of Bills

Bills for power shall be rendered monthly and shall be payable at the Division of Fiscal Accounting and Disbursement located in BPA's Headquarters at 1002 N.E. Holladay Street, Portland, Oregon. Payments by mail should be sent to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

At its option, BPA may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

Bills shall be due by close of business on the 20th day after the date of the bill (Due Date). Should the 20th day be a Saturday, Sunday, or holiday (celebrated by the purchaser), the Due Date shall be the next following business day.

Bills not paid in full on or before close of business on the Due Date shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the unpaid amount or $50. In addition, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the Due Date. In order to avoid assessment of late payment charges for metered mail received subsequent to the Due Date, the payment must bear a postal department cancellation which demonstrates that the payment was mailed on or before the Due Date.

Whenever a power bill or a portion thereof remains unpaid subsequent to the Due Date and after giving 30 days advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest.

APPENDIX E

TRANSMISSION RATE SCHEDULES

SCHEDULE FPT-83.1

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes FPT-2 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once a year. It is available for firm transmission of electric power and energy using the FCRTS. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as firm availability of service is required.

SECTION II. RATES:

A. Full-Year Service:

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge, and Intertie Charge, as applicable and as specified in the Agreement.

1. Main Grid Charge:

The Main Grid Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by \$.0326 per mile;

b. Main Grid Interconnection Terminal Factor - \$.42.

c. Main Grid Terminal Factor - \$.32;

d. Main Grid Miscellaneous Facilities Factor - \$1.56;

2. Secondary System Charge:

The Secondary System Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by \$.1879 per mile;

b. Secondary Transformation Factor - \$2.38;

c. Secondary System Intermediate Terminal Factor - \$.76;

d. Secondary System Interconnection Terminal Factor - \$.95.

3. Intertie Charge:

For use of Pacific Northwest - Pacific Southwest Intertie facilities - $5.03.

B. Partial- Year Service:

The monthly charge per kilowatt of billing demand shall be as specified in Section 2.A. for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

   a. during months for which service is specified, the monthly charge defined in Section 2.A., and

   b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

SECTION III. DETERMINATION OF BILLING DEMAND:

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand in kilowatts specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month; or

C. the Ratchet Demand.

SCHEDULE FPT-83.3

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes FPT-2 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 3 years. It is available for firm transmission of electric power and energy using the FCRTS. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as firm availability of service is required.

SECTION II. RATES

A. Full-Year Service:

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge, and Intertie Charge, as applicable and as specified in the Agreement.

1. Main Grid Charge:

The Main Grid Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $.0326 per mile;

b. Main Grid Delivery Terminal Factor - $.42.

c. Main Grid Terminal Factor - $.32;

d. Main Grid Miscellaneous Facilities Factor - $1.56;

1. Secondary System Charge:

The Secondary System Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $.1879 per mile;

b. Secondary Transformation Factor - $2.38;

c. Secondary System Intermediate Terminal Factor - $.76;

d. Secondary System Interconnection Terminal Factor - $.95.

3. Intertie Charge:

For use of Pacific Northwest - Pacific Southwest Intertie facilities - \$5.03.

B. Partial-Year Service:

The monthly charge per kilowatt of billing demand shall be as specified in Section 2.A for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

   a. during months for which service is specified, the monthly charge defined in Section 2.A., and

   b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

SECTION III. DETERMINATION OF BILLING DEMAND:

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand in kilowatts specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SCHEDULE FPT-83.5

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes FPT-1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 5 years. It is available for firm transmission of electric power and energy using the FCRTS. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as firm availability of service is required.

SECTION II. RATES

A. Full-Year Service:

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge, and Intertie Charge, as applicable and as specified in the Agreement.

1. Main Grid Charge:

   The Main Grid Charge shall be the sum of one or more of the following factors as specified in the Agreement:

   a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $.0326 per mile;

   b. Main Grid Delivery Terminal Factor - $.42.

   c. Main Grid Terminal Factor - $.32;

   d. Main Grid Miscellaneous Facilities Factor - $1.56;

2. Secondary System Charge:

   The Secondary System Charge shall be the sum of one or more of the following factors as specified in the Agreement:

   a. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $.1879 per mile;

   b. Secondary Transformation Factor - $2.38;

   c. Secondary System Intermediate Terminal Factor - $.76;

   d. Secondary System Interconnection Terminal Factor - $0.95.

3. Intertie Charge:

For use of Pacific Northwest - Pacific Southwest Intertie facilities - $5.03.

B. Partial-Year Service:

The monthly charge per kilowatt of billing demand shall be as specified in Section 2.A for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

    a. during months for which service is specified, the monthly charge defined in Section 2.A., and

    b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

SECTION III. DETERMINATION OF BILLING DEMAND:

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand in kilowatts specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SCHEDULE IR-83

INTEGRATION OF RESOURCES

SECTION I. AVAILABILITY:

This schedule supersedes IR-1 and is available for intraregional firm transmission service and other appropriate services provided for electric power and energy using the FCRTS, exclusive of the Intertie segments.

SECTION II. RATES:

The monthly charge shall be the sum of:

A. \$0.3126 per kilowatt of billing demand, except as otherwise provided in Subsection (3) below, and

B. \$.00098 per kilowatthour of billing energy.

C. For Points of Integration (POI) specified in the Agreement as being short distance POI's, for which FCRTS facilities are used for a distance of less than 75 circuit miles, the demand charge shall be determined in accordance with the following formula:

$$[.2 + \frac{.8}{75} \text{ X (transmission distance)}] \text{ X \$0.3126 per kW of billing demand,}$$

where:

the billing demand is the demand level specified in the Agreement for such POI, and the transmission distance is the circuit miles between a POI for a generating resource of the customer and a designated Point of Delivery (POD) serving load of the customer.

SECTION III. DETERMINATION OF BILLING DEMAND AND BILLING ENERGY:

The billing demand shall be the largest of:

A. the Total Transmission Demand in kilowatts as specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month; or

C. the Ratchet Demand.

The billing energy shall be the sum of all hourly amounts of power in kilowatt-hours wheeled for the billing month under the Agreement.

SCHEDULE IS-83

SOUTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes ET-2 with respect to deliveries using the Pacific Northwest - Pacific Southwest, or Southern Intertie and is available for all transmission on the Southern Intertie.

SECTION II. RATES:

The charge for transmission of non-Federal power on the Pacific Northwest - Pacific Southwest Intertie shall be 1.55 mills/kWh.

SCHEDULE IN-83

NORTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes ET-2 with respect to interregional delivery using the Northern Intertie and is available for all transmission on the Northern Intertie.

SECTION II. RATES:

The charge for transmission of non-Federal power on the Northern Intertie shall be 1.45 mills/kWh.

SCHEDULE IE-83

EASTERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes ET-2 with respect to interregional delivery using the Eastern Intertie and is available for all nonfirm transmission on the Eastern Intertie.

SECTION II. RATES:

The charge for transmission of non-Federal power on the Eastern Intertie shall be 2.23 mills/kWh.

SCHEDULE ET-83

ENERGY TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes ET-1 and ET-2, unless otherwise specified in the Agreement, with respect to delivery using FCRTS facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie, and is available for nonfirm transmission between points in the Pacific Northwest upon BPA's determination of available capacity. This rate is not available for the transmission of energy which cannot be interrupted.

SECTION II. RATES:

The charge for such nonfirm transmission of non-Federal electric energy shall be 1.86 mills/kWh.

SCHEDULE UFT-83

USE-OF-FACILITIES TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes UFT-1 and UFT-2, unless otherwise provided in the Agreement, and is available for firm transmission over specified FCRTS facilities.

SECTION II. RATES:

The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with Section 3.

SECTION III. DETERMINATION OF TRANSMISSION RATE:

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA, and which are used to transmit electric power and energy:

   1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the FCRTS financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

   2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands. The annual cost per kilowatt of Transmission Demand for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following forumula:

$$\frac{A}{D}$$

Where

A = The annual cost of such facility as determined in accordance with A.1 above.

D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2 above.

The annual cost per kilowatt of facilities listed in the Agreement which are owned by another entity, and used by BPA for making deliveries to the transferee, shall be determined from the costs specified in the Agreement between BPA and such other entity.

SECTION IV. DETERMINATION OF BILLING DEMAND:

Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of billing demand shall be the largest of:

A. the Transmission Demand in kilowatts specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. The Ratchet Demand.

SCHEDULE TGT-1

TOWNSEND-GARRISON TRANSMISSION

SECTION I. AVAILABILITY:

This schedule shall apply to all agreements which provide for the firm transmission of electric power and energy over transmission facilities of BPA's section of the Montana [Eastern] Intertie.

SECTION II. RATES:

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Transmission System. Annual revenues plus credits for Government use should equal annual costs of the facilities, but in any given year there may be either a surplus or a deficit. Such surpluses or deficits for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements from firm transmission use will be decreased by any revenues received from nonfirm use and credits for all Government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower will be the unit rate.

If the Government provides firm transmission service in its section of the Montana [Eastern] Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by the Government for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer. During an estimated 1 to 3-year period following the commercial operation date of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500 kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge. However, starting 1 month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

A. Nonfirm Transmission Charge:

This charge will be filed as a separate Rate Schedule and revenues received thereunder will reduce the amount of revenue to be collected under the Intertie Charge below.

B. Intertie Charge for Firm Transmission Service

$$\text{Intertie Charge} = [(\text{TAC}/12 - \text{NFR}) \times \frac{(\text{CR} - \text{EC})}{\text{TCR}}]$$

SECTION III. DEFINITIONS:

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500-kV transmission line including terminals, and prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) an allowance for Bonneville's general administrative costs which are appropriately allocable to such facilities; and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by the Government on account of any reduction in Transmission Demand, termination or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Nonfirm Revenues, which are equal to (1) the product of the Nonfirm Transmission Charge described in 2(A) above, and the total nonfirm energy transmitted over the Townsend-Garrison line segment under such charge for such month; plus (2) the product of the Non-Firm Transmission Charge and the total nonfirm energy transmitted in either direction by the Government over the Townsend-Garrison line segment for such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500-kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in firm transmission agreements described in section 1; and (2) the Government's firm capacity requirement. The Government's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange credit for each customer which is the product of (1) the ratio of investment in the Townsend-Broadview 500-kV transmission line to the investment in the Townsend-Garrison 500-kV transmission line; and (2) the capacity which the Government obtains in the Townsend-Broadview 500-kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSP)

1. Interpretation:

The provisions in the Agreement to which these GTRSP are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the provision in the Agreement shall prevail.

2. General Provisions:

Services provided under all transmission rate schedules shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and these provisions. The meaning of terms used in the transmission rate schedules shall be as defined in the Agreements or any of the above acts or provisions which are attached to the Agreements.

3. Bonneville Service Area:

The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions, and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the BPA wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal System.

4. Availability of Transmission Service:

Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal obligations will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identified in the Transmission Rate Schedules, dated 1983, or as subsequently revised.

5. Billing Details:

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will normally be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which is the greater of one fourth percent (0.25) of the amount unpaid or $50. Thereafter, a charge of one-twentieth percent (0.05) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full.

   Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day shall bear a postal department cancellation in order to avoid assessment of such further charges.

   BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after given 30 days advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

   If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule applications are rounded to whole dollar amounts by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the Measured or Scheduled Demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

6. Adjustment for Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the Agreement, may be made by increasing the amount delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in the Wholesale Power General Rate Schedule Provisons.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to the customer at a POD or for a system at any time that the average power factor for all classes of power delivered to the customer at such POD or for such system is below 75 percent lagging or 75 percent leading.

7. Definitions. Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

   a. Agreement:

   A transmission agreement between BPA and a transmission customer to which these rate schedules and provisions may be attached.

   b. Eastern Intertie:

   Those transmission facilities consisting of the Townsend-Garrison 500-kV transmission line, including terminals and, prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison.

   c. Electric Power:

   (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical). Electric peaking capacity (kW), or electric energy (kWh), or both.

   d. Firm Transmission Service:

   Transmission service which BPA provides for any non-BPA power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. Integrated Network:

Those transmission facilities which primarily perform the function of bulk transmission of electric power in the Pacific Northwest, excluding facilities not segmented to the Network in the Cost of Service Analysis used in BPA's rate development.

f. Main Grid:

As used in the FPT rate schedule, that portion of the FCRTS with facilities rated 230-kV and higher, exclusive of those designated as Interties.

g. Main Grid Distance:

As used in the FPT rate schedule, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

h. Main Grid Interconnection Terminal:

As used in the FPT rate schedule, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

i. Main Grid Miscellaneous Facilities:

As used in the FPT rate schedule, switching, transformation, and other facilities of the Main Grid not included in other factors.

j. Main Grid Terminal:

As used in the FPT rate schedule, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

k. Measured Demand. Except where deliveries are scheduled as hereinafter provided, the Measured Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands delivered to a customer at each POD during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the Agreement. BPA, in determining the Measured Demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal Sytem Facilities; and (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. For those Agreements to which BPA is a party and which provide for delivery of more than one class of electric power to the customer at any POD, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the Agreement. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

If the flow of electric energy to a customer's system through two or more POD's cannot be adequately controlled because such points are interconnected within the customer's system, or the customer's system is interconnected directly or indirectly with the Federal System, the Measured Demand for each class of power for such system for any billing period shall be the largest of the hourly amounts of such class of power which are scheduled for delivery to the customer during each time period specified in the applicable rate schedule.

l. Nonfirm Transmission Service:

Transmission service which BPA will provide for non-BPA power, only if and when BPA determines that capacity is available.

m. Northern Intertie:

Those transmission facilities consisting of two 500-kV lines between Custer substation and the United States-Canadian border, one 500-kV line between Custer and Monroe substations, and two 230-kV lines from Boundary substation to the United States-Canadian border, and the associated substation facilities.

n. Point of Integration (POI):

Connection points between the FCRTS and non-BPA facilities where power to be wheeled is made available to BPA.

o. Point of Delivery (POD):

Connection points between the FCRTS and non-Federal facilities where non-Federal power wheeled is delivered to a customer by BPA.

p. Pacific Northwest - Pacific Southwest Intertie:

Those transmission facilities consisting of two 500-kV AC lines and one 800-kV DC line between the John Day and Celilo substations and the Oregon-California border, and associated substation facilities.

q. Ratchet Demand:

The maximum past or present demand established during the previous 11 billing months based on the highest scheduled demand during that time.

r. Scheduled Demand:

The largest of hourly amounts of power wheeled which are scheduled by the customer during the time period specified in the rate schedules.

s. Secondary System:

As used in the FPT rate schedule, that portion of the FCRTS facilities with operating voltage of 115-kV or 69-kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69-kV) FCRTS facilities which may be used on a use-of-facility basis.

t. Secondary System Distance:

As used in the FPT rate schedule, the number of circuit miles of Secondary System transmission lines between the secondary POI or the Main Grid and the POD or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

u. Secondary System Interconnection Terminal:

As used in the FPT rate schedule, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

v. Secondary System Intermediate Terminal:

As used in the FPT rate schedule, the first and final terminal facilities in the Secondary System exclusive of the Secondary System Interconnection terminals.

w. Secondary Transformation:

As used in the FPT rate schedule, transformation from Main Grid to Secondary System facilities.