1982 FINAL WHOLESALE RATE PROPOSAL

ADMINISTRATOR'S RECORD OF DECISION

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BONNEVILLE POWER ADMINISTRATION
U. S. DEPARTMENT OF ENERGY

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I. Introduction

This document has been prepared to trace the decision-making process that I, as Administrator of the Bonneville Power Administration (BPA), employed in overseeing development of the attached proposed wholesale power rate schedules (Exhibit A). The proposed wholesale power rate schedules are hereby submitted to the Federal Energy Regulatory Commission (FERC) for final confirmation and approval. I am at this time requesting that FERC grant interim approval of these rates so that they may become effective on October 1, 1982.

BPA published in the Federal Register on October 15, 1981, a "Notice of Intent to Develop Revised Wholesale Power Rates" (46 FR 50838) and on March 31, 1982, a "Notice of Proposed Wholesale Power Rate Adjustment" (47 FR 13710). This initial proposal for revised rates gave notice that BPA needed an increase in revenues from its rates to meet its financial obligations. The proposed increase amounted to approximately 73 percent in the average rate charged preference customers.

In accord with provisions of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) and BPA's rate adjustment procedures, BPA commenced its formal hearing process on April 12, 1982, at Portland, Oregon. Thirty-nine parties of record participated in seven weeks of hearings which included presentation of BPA's proposal, clarifying questions, cross-examination of BPA witnesses, presentation of testimony and cross-examination of the parties' witnesses, and presentation of rebuttal and cross-examination by all parties. Final oral argument and the close of the hearings occurred July 2, 1982.

In addition to the formal hearing process, the Regional Act and BPA's procedures provide for substantial public participation in developing revised rates. BPA's procedures designate interested people who wish to participate in this process as "participants". This designation was established to give the public the maximum opportunity to participate and have its views considered without assuming the obligations incumbent upon the "parties." As participants, interested individuals were provided opportunity to include in the record their views on BPA's proposal and to receive periodic summaries of the progress of the formal hearing.

To facilitate public involvement and receipt of comments, BPA held field hearings at eight locations around the region and in San Francisco, California, during the weeks of April 12 through 23, 1982, and received comments from 287 interested people. In addition, BPA received approximately 250 letters and 25 telephone calls commenting on the rate proposal or rate development process. To provide additional opportunity for the public to comment on the hearing record, BPA held simultaneously seven hearings at various regional locations on June 28, 1982.

The record from the formal and field hearings consists of approximately 9,000 pages of transcripts and 3,200 pages of testimony in addition to the letters mentioned above. This record formed the basis from which the staff prepared and published the Staff Evaluation of Official Record on July 9, 1982, in which the staff commented on the issues raised by the parties and participants. In turn, the parties were given the opportunity to comment on the Staff Evaluation of Official Record in their Reply Briefs submitted on July 19, 1982. In total, approximately 1,000 pages of legal briefs were filed by the parties and BPA's counsel.

Following the close of the hearing, BPA developed the proposed wholesale power rate schedules which are based on studies conducted by BPA and the comments and suggestions received throughout the ratemaking process. The studies include: (1) Revenue Forecast Study, projects revenues to be derived from current and proposed rates; (2) Repayment Study, determines revenue requirements; (3) Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis, determines cost variation as a function of the time of service and evaluates the additional costs faced by BPA in meeting load growth; (4) Cost of Service Analysis (COSA), identifies the embedded costs associated with providing BPA's various services; (5) Wholesale Power Rate Design Study (WPRDS), outlines the ratemaking process including adjustments based on the results of the other studies used in developing the specific wholesale power rate schedules; and (6) Environmental Impact Statement (EIS) on the wholesale power rate filing. These studies were originally published on March 31, 1982, to support the initial rate proposals. The draft EIS was released in April. They were revised in the process of developing the final rate schedules and summaries of these revisions are documented herein.

The final Repayment Study identifies the need for revenues of $2.2 billion in FY 1983 to meet BPA's financial obligations. This is an increase of $814.5 million over the $1.4 billion that would be collected in FY 1983 under the existing rates. The impact of the rate increase on BPA's preference customers averages 60 percent. The range of increases for these customers is 54.4 percent to 62.2 percent after adjusting for the low density discount. The average increase for municipalities, public utility districts, cooperatives, and Federal agencies is 60.4 percent, 59.7 percent, 58.6 percent, and 59.9 percent, respectively.

The impacts of this proposal on the investor-owned utilities (IOU's) are two-fold. First, any IOU participating in the residential exchange as provided for in Section 5(c) of the Regional Act can purchase an amount of power equivalent to 70 percent of the utility's residential and small farm load during the year beginning July 1, 1982, and 80 percent during the year beginning July 1, 1983, at the same priority firm rate charged to BPA's preference customers. Any IOU that signs a power sales contract with the Administrator for purchases to meet its load growth or deficits will be served at the NR-2 rate. The average rate to these customers will be 29.5 mills per kilowatthour, which is a 5 percent decrease over the NR-1 rate.

BPA's direct-service industrial customers (DSI's) will be served at an average rate of 25.9 mills per kilowatthour. This is a 50 percent increase in the Industrial Firm rate, IP-2.

Another rate of significant concern to BPA's customers is the Wholesale Firm Capacity Rate, CF-2. This rate is set at a contract year rate of $36.72 per kilowatt per year which is an increase of 44 percent over the previous rate.

BPA markets a significant amount of nonfirm energy to Pacific Southwest utilities under its nonfirm energy rate schedule. The proposed rate, NF-2, consists of the following three components: (1) standard rate, (2) spill rate, and (3) incremental rate. It is designed to gain greater customer acceptance than the NF-1 rate while maintaining an equitable price for nonfirm energy. A portion of the sales under this rate will be provided with a guaranteed delivery provision. The average sales under the NF-2 rate are estimated to be at 11.2 mills per kilowatthour, which is a 19 percent increase over the NF-1 rate.

This proposal includes three entirely new rates for BPA: (1) Surplus Firm Power Rate, SP-1; (2) Surplus Firm Energy Rate, SE-1; and (3) Energy Broker Rate, EB-1. The SP-1 and SE-1 rates are designed to allow BPA to market resources that are surplus to those necessary to meet firm loads. The rates are based on the cost of these surplus resources. The EB-1 rate will allow BPA to market energy that would otherwise be spilled as a result of there not being any available concurrent market under the NF-2 rate. These transactions will be conducted through the Western System Coordinating Council.

II. Legal Requirements

A. General Rate Guidelines

Section 6 of the Bonneville Project Act (16 U.S.C. § 832e) requires that:

> "Schedules of rates and charges for electric energy produced at the Bonneville Project and sold to purchasers as in this Act provided shall be prepared by the Administrator and become effective upon confirmation and approval thereof by the Federal Power Commission; and such rates and charges shall also be applicable to dispositions of electric energy to Federal agencies. Subject to confirmation and approval by the Federal Power Commission, such rate schedules may be modified from time to time by the Administrator, and shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy. The said rate schedules may provide for uniform rates or rates uniform throughout the prescribed transmission areas in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville Project."

Section 7 of the Bonneville Project Act (16 U.S.C. § 832(f)) provides in part:

> "Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rates schedules to the capacity of the electric facilities of the Bonneville Project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years."

Parallel requirements appear in the Federal Columbia River Transmission System Act (16 U.S.C. 838). For example, Section 9 of that Act provides:

> "Schedules of rates and charges for the sale, including dispositions to Federal agencies, of all electric power made available to the Administrator pursuant to Section 8 of this Act or otherwise acquired, and for the transmission of non-Federal electric power over the Federal transmission system, shall become effective

upon confirmation and approval thereof by the Federal Power Commission. Such rate schedules may be modified from time to time by the Secretary of the Interior, acting by and through the Administrator, subject to confirmation and approval thereof by the Federal Power Commission, and shall be fixed and established (1) 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, (2) having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years and payments provided for in section 11(b)(9), and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith."

Regional Act. The foregoing requirements are similarly restated in the Section 7(a)(1) of the Act (16 U.S.C.A. 839e(a)(1)) provides, in part:

"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), section 5 of the Flood Control Act of 1944, and the provisions of this Act."

Section 7(a)(2) also provides:

"Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates--

"(A) 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,

"(B) are based upon the Administrator's total system costs, and

"(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system."

Section 11(b)(9) (16 U.S.C.A. § 839i(b)(9) of the Transmission System Act enables the Administrator of BPA to make:

". . . such payments to the credit of the reclamation fund or other funds as are required by or pursuant to law to be made into such funds in connection with reclamation projects in the Pacific Northwest: Provided, That this clause shall not be construed as permitting the use of revenues for repayment of costs allocated to irrigation at any project except as otherwise expressly authorized by law. . . ."

Recognizing that many hydroelectric projects serve other purposes such as navigation, flood control, and irrigation, in addition to the generation of electric power, Section 7 of the Bonneville Project Act further provides that:

"In computing the cost of electric energy developed from water power created as an incident to and a byproduct of the construction of the Bonneville project, the Federal Power Commission may allocate to the costs of electric facilities such a share of the cost of facilities having joint value for the production of electric energy and other purposes as the power development may fairly bear as compared with such other purposes."

B. Repayment Criteria

The mechanism for modifying the Administrator's rates was statutorily mandated by Pub. L. 89-448 (June 14, 1966, 80 Stat. 200), Section 2 of which provides in pertinent part:

> "Sec. 2. The Secretary of the Interior shall prepare, maintain, and present annually to the President and the Congress a consolidated financial statement for all projects heretofore or hereafter authorized, . . . and he shall, if said consolidated statement indicates that the reimbursable construction costs of the projects, or any of the projects, covered thereby which are chargeable to and returnable from the commercial power and energy so marketed are likely not to be returned within the period prescribed by law, take prompt action to adjust the rates charged for such power and energy to the extent necessary to assure such return."

Based on an opinion of BPA's General Counsel dated February 6, 1979, BPA has excluded from its Repayment Study those Federal power projects authorized by Congress, but not yet in service. However, BPA still includes these uncompleted projects in its annual reports to the President and Congress. The exclusion of projects not yet in service is based on the fact that the legislative history of Pub. L. 89-448 indicates that repayment of a Federal project is scheduled "within 50 years following its being placed into service" (H.R. Rep. No. 1409, 89th Cong. 2d Sess. (1966)). (Emphasis added.)

In addition to this requirement, statutory limitations have been placed on the extent to which power revenues may subsidize reclamation projects. Pub. L. 89-561 (September 7, 1966, 80 Stat. 707, et seq.) provides in Section 6:

> "(b) It is declared to be the policy of the Congress that reclamation projects hereafter authorized in the Pacific Northwest to receive financial assistance from the Federal Columbia River Power System shall receive such assistance only from the net revenues of that system as provided in this subsection, and that their construction shall be so scheduled that such assistance, together with similar assistance for previously authorized reclamation projects (including projects not now receiving such assistance for which the Congress may hereafter authorize financial assistance) will not cause increases in the rates and charges of the Bonneville Power

Administration. It is further declared to be the policy of the Congress that the total assistance to all irrigation projects, both existing and future, in the Pacific Northwest shall not average more than $30,000,000 annually in any period of twenty consecutive years. Any analyses and studies authorized by the Congress for reclamation projects in the Pacific Northwest shall be prepared in accordance with the provisions of this section. As used in this section, the term 'net revenues' means revenues as determined from time to time which are not required for the repayment of (1) all costs allocated to power at projects in the Pacific Northwest then existing or authorized, including the cost of acquiring power by purchase or exchange, and (2) presently authorized assistance from power to irrigation at projects in the Pacific Northwest existing and authorized prior to the date of enactment of this subsection. [16 U.S.C. 835 1]

"(c) On December 20, 1974, and thereafter at intervals coinciding with anniversary dates of Federal Power Commission general review of the rates and charges of the Bonneville Power Administration, the Secretary of the Interior shall recommend to the Congress any changes in the dollar limitations herein placed upon financial assistance to Pacific Northwest reclamation projects that he believes justified by changes in the cost-price levels existing on July 1, 1966, or by other relevant changes of circumstances." [16 U.S.C. 835m]

Based on these requirements, I conducted a Repayment Study in a manner consistent with that approved by the Congress in its consideration of Pub. L. 89-448. (See H.R. Rep. No. 1409, 88th Cong., 2d Sess. 7-8 (1966).) The Repayment Study indicated that existing rates are insufficient to repay the Federal capital investment over a reasonable period of years. The Repayment Study also found that, because BPA's recent revenues have been lower than expected, BPA owed the Treasury $112.4 milllion on September 30, 1980, for accumulated unpaid interest expenses. At the end of FY 1981 BPA made an interest payment of 3.9 million, so that the outstanding deferral on September 30, 1981, was $108.6 million. For FY 1982, an additional cash deficit of $116.6 million is anticipated, making the projected accumulated deficit of unpaid interest expense at the end of FY 1982 approximately $217.9 million.

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.

I find that repayment of the deferral over a period of three years is consistent with my obligation to keep overall rates as low as possible consistent with sound business principles. Accordingly, we developed wholesale power rates in an initial form, and finally in the form appended hereto, at a level sufficient to fully repay the amount of the deferral over three years, FY 1983 through FY 1985. In addition, these rates are set at a level sufficient to repay the normal required amortization that would have been scheduled during the FY 1983 through FY 1985 period if no deferral existed.

I find that these rates will be sufficient to meet the statutory requirements of recovering the costs of production, acquisition, conservation, and transmission of electric power (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years as well as other costs and expenses incurred pursuant to the Regional Act and other provisions of law; to pay the principal, premiums, discounts, expenses and interest in connection with bonds issued on behalf of BPA; and to make payments to the credit of the reclamation fund required to be paid from electricity sales. Furthermore, I find, as demonstrated by the Repayment Study, that the rates in Exhibit A are overall the lowest possible consistent with sound business principles. I further find that reclamation projects have been scheduled in such a manner as to assure that the reclamation project assistance required to be paid by BPA will not average more than $30,000,000 annually in any period of 20 consecutive years.

C. Equitable Recovery of Transmission Costs

In addition to the requirements relating to wholesale power rates, Section 10 of the Federal Columbia River Transmission System Act provides:

> "The said schedules of rates and charges for transmission, the said schedules of rates and charges for the sale of electric power, or both such schedules, may provide, among other things, for uniform rates or rates uniform throughout prescribed transmission areas. The recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system."

Section 7(a)(2)(C) of the Regional Act restates the requirement that transmission costs be equitably allocated by providing that:

"Rates established under this section shall become effective only . . . upon a finding by the [Federal Energy Regulatory] Commission, that such rates--

* * * *

"(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system."

In order to meet the above-noted requirement, among others, BPA prepared a Repayment Study, to determine the minimum level of revenue required to recover all costs over the repayment period, and a Cost of Service Analysis (COSA) to identify the embedded costs associated with providing BPA's various services.

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. As explained in the COSA, transmission costs are divided into seven segments. An analysis was then performed on each segment to determine the amount of Federal power and non-Federal power using the segment. Although the segmented portion of the transmission system partially used by wheeling customers is identified in the COSA, BPA has not allocated costs to that use in this rate filing. The question of an equitable allocation to non-Federal power is of great concern to me. By order issued August 3, 1982, the FERC approved BPA 1976 transmission rates with directions to adjust BPA's accounting system to assure equitable allocation of recovery of cost between Federal and non-Federal power utilizing the transmission system (20 FERC ¶61,142). Basic questions affecting equity (e.g. identifying wheeling service provided) are currently under review in the development of BPA's transmission policy. Other factors have also influenced my decision to not file revised transmission rates (For example, questions of intra class equity arise because a substantial number of wheeling customers operate under contracts which do not permit rate adjustments during the rate period.) The uncertainities surrounding how these basic questions will be resolved in the months ahead plus the fact that the magnitude of a wheeling rate increase at this time would be nominal, has allowed me to conclude that I will not file revised transmission rates at this time. I plan to revise my transmission rates soon in order to reflect the results of BPA's transmission policy and to incorporate FERC's recommendations.

D. Equitable Sharing of Benefits by Regions

In addition to the general rate guidelines and those relating to transmission, I am charged with certain marketing restrictions relating to sales outside the Pacific Northwest by the Pacific Northwest Regional Preference Act (Pub. L. 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, contains the statutory mandate that:

"All benefits from such exchanges, including resulting increases in firm power, shall be shared equitably by the areas involved, having regard to the secondary energy and other contributions made by each."

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, this is expressly noted in Section 7(k) of the Regional Act, which provides, in part:

"Notwithstanding any other provision of this Act, all rates or rate schedules for the sale of nonfirm electric power within the United States, but outside the region, shall be established after the date of this Act by the Administrator in accordance with the procedures of subsection (i) of this section (other than the first sentence of paragraph (6) thereof) and in accordance with the Bonneville Project Act, the Flood Control Act of 1944, and the Federal Columbia River Transmission System Act.

Furthermore, the Senate and House Committee Reports on Pub. L. 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 <u>all power sales</u>, not just exchanges of energy or capacity under Section 5 of the Regional Preference Act. Pursuant to that Congressional expression, I have adopted the NF-2 rate which I find results in an equitable sharing between the Pacific Northwest and Pacific Southwest of the benefits of sales of secondary energy and at the same time keeps rates to BPA's Pacific Northwest regional consumers at the lowest possible cost consistent with sound business principles.

E. <u>Regional Act Rate Pools</u>

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 the following requirements for public body, cooperative, Federal agency and residential exchange loads (Section 5(c) of the Regional Act) for the period prior to 1985:

"(b)(1) 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 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 as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources."

Rates for direct-service industrial customers are established, for the period prior to July 1985, under the following subsections of Section 7:

"(c)(1) 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 incurrred 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 receovered through rates applicable to other customers;

* * * *

(3) The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." (Emphasis added.)

Finally, rates for all other firm power sales under the Regional Act are established pursuant to Section 7(f):

(f) Rates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be based upon the cost of the portions of Federal base system resources, purchases of power under section 5(c) of this Act and additional resources which, in the determination of the Administrator, are applicable to such sales. (Emphasis added.)

I have considered the new arguments in the opening brief of Puget Sound Power and Light Company (pp. 23) and the Reply Memorandum of BPA

Counsel (pp. 1-4 and Attachment A) and conclude that the express words of the Regional Act contemplate the creation of three rate pools. Futhermore, despite an apparently ambiguous legislative history, I find that it is ultimately my obligation to determine the resources used to serve the DSI 7(c) load and the 7(f) load. I believe that this view is consistent with a statement made by one of the primary sponsors of S. 885 (which are enacted as the Regional Act) in the House, Congressman Dingell:

> "The bill obligates the Administrator to offer full requirements contracts to the region's investor-owned utilities. However, only power that is surplus to the Administrator's existing responsibilities or power that is developed by these utilities may be provided pursuant to this obligation. These contracts will not disadvantage the Administrator's other customers and provide no special benefit to these companies' stockholders." 126 (Cong. Rec. H9848 (daily ed. September 29, 1980)(remarks of Rep. Dingell)).

The entire record convinces me that the DSI's were to pay "substantially higher rates" and will do so by paying the costs of residential exchange under this Regional Act not anticipated to be recovered through other rates. However, to require them to pay, in addition, certain new resource costs, was not contemplated by Congress in my view because to do so would disadvantage one group of my "other customers" - - the DSI's.

Because portions of last year's record regarding two versus three rate pools are incorporated into the record regarding this rate adjustment, I feel compelled to attach hereto, as Exhibit B, my rationale for adopting three rate pools in last year's proceeding. Because that rationale is based on my interpretation of the requirements of law and because the law has not changed, I expressly re-adopt the rationale expressed in Exhibit B.

F. <u>Confirmation and Approval</u>

Section 7(i)(6) of the Regional Act provides:

> "The final decision of the Administrator shall become effective on confirmation and approval of such rates by the Federal Energy Regulatory Commission pursuant to subsection (a)(2) of this section. The Commission shall have the authority, in accordance with such procedures, if any, as the Commission shall promptly establish and make effective within one year after the enactment of this Act, to approve the final rate submitted by the Administrator on an interim basis, pending the

> Commission's final decision in accordance with such subsection. Pending the establishment of such procedures by the Commission, if such procedures are required, the Secretary is authorized to approve such interim rates during such one-year period in accordance with the applicable procedures followed by the Secretary prior to the effective date of this Act. Such interim rates, at the discretion of the Secretary, shall continue in effect until July 1, 1982."

On June 24, 1981, pursuant to section 7(i)(6) of the Act and Secretary of Energy Delegation Order No. 0204-33, as amended and supplemented, the Assistant Secretary for Conservation and Renewable Energy of the Department of Energy placed BPA's 1981 wholesale and transmission rates into effect on an interim basis, and filed such rates with the Federal Energy Regulatory Commission (FERC) requesting that they be granted final confirmation and approval. (46 F.R. 33542). Pursuant to the Assistant Secretary's order, the rates were placed into effect from July 1, 1981, "through June 30, 1982, or until FERC confirms and approves them or substitute rates on a final basis." (46 F.R. 33569). To date, the FERC has neither confirmed and approved the rates placed into effect by the Assistant Secretary nor any substitute rates on a final basis. The FERC has, however, by order dated June 22, 1982, extended the interim approval of BPA's 1981 power and transmission rates until January 1, 1983 (19 FERC ¶ 61,281).

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. Notwithstanding that the FERC has not finalized these rules, I am preparing this Record of Decision so that it conforms with the requirements of section 300.10(e), the section of the rules pertinent to the Administrator's Record of Decision.

III. Preliminary Issues - Loads and Resources

A. Introduction

Before BPA can determine the costs that must be recovered from its rates and therefore the level of its rates in FY 1983, BPA must project the amount of load it will be required to meet and the resources available to meet that load. These issues taken together are essential in determining the costs to be included in the rate studies. The determination of loads and resources is a dynamic process that is based on assumptions underlying forecasts, available resources, and policy determinations for resource acquisitions. As such, these assumptions and policies are the initial focus in the development of rates.

B. Loads

The initial step in the development of BPA's wholesale power rates is to forecast the loads that will be placed on BPA during the critical period (20 month planning period established in accord with the Pacific Northwest Coordination Agreeement) by the customer groups. In turn, the load forecasts are used to establish the need for resources to meet those loads and to project costs and revenues. Forecasting loads is a complex process that involves many assumptions about the effects of changing economic conditions and attitudes on the demand for electricity by BPA's customer groups. Because of the complex nature of forecasting and the importance of loads to the determination of costs and ultimately rates, BPA's load forecasts were given considerable scrutiny during the rate hearing.

BPA's load forecasts for both peak and energy needs consist of a number of individual forecasts developed from a variety of sources. These forecasts are: (1) BPA Utility Type loads which are nongenerating and small generating public agency loads as well as contracted Federal agency loads and United States Bureau of Reclamation (USBR) "reserved energy" requirements; (2) Direct-Service Industrial (DSI) loads; (3) Investor-Owned Utility (IOU) net requirements; (4)Generating Public Agency firm transfers; and (5) residential exchange loads. Expected savings from existing conservation programs are incorporated in these load forecasts. The development of each forecast is discussed individually below.

1. BPA Utility Type Loads

BPA traditionally has used a sum-of-the-parts methodology in forecasting BPA Utility Type loads. This forecast consisted of monthly estimates of: (1) nongenerating and small generating utility loads prepared by the utilities or with the aid of BPA staff; (2) BPA contracted Federal Agency loads, determined by BPA; and (3) USBR "reserved energy" requirements, determined by BPA staff in cooperation with the USBR.

BPA Utility Type loads are a significant portion of BPA's total loads. Therefore, it is essential that the methodology, from which this forecast is derived, be reliable and that the results reflect the best estimates of future electricity consumption. As evidenced in Exh. BPA-9, pp. 8-9 and Attachments 8 and 9, recent comparisons of actual to forecasted loads indicate that the BPA Utility Type load projections based on the sum-of-the-parts methodology have not been reliable. Additionally, the most recent BPA Utility Type load forecast derived from the sum-of-the-parts methodology did not adequately reflect expected electricity consumption in light of the current recession and anticipated timing of recovery. Therefore, for purposes of this year's rate filing, BPA has elected to use a time series analysis (ARIMA) rather than the sum-of-the-parts methodology to forecast BPA Utility Type loads. ARIMA modeling was chosen rather than another methodology because it is an effective short-term forecasting tool which is being used more extensively by other utilities for forecasting purposes (Lenzen, BPA, Exh. BPA-9, p. 10; TR. 4413, 4418, 4423).

BPA's initial forecast of BPA Utility Type loads employed two ARIMA models. These two models were combined mathematically to reflect current and future economic conditions based on Data Resources Incorporated (DRI) economic data. Because neither of the two alternative statistically valid ARIMA models individually reflected anticipated energy consumption for BPA Utility Type loads in light of DRI economic data, the combined models were used (Lenzen, BPA, Exh. BPA-9, pp. 10-11).

Various parties criticized BPA for not employing more recent data in its initial forecast of BPA Utility Type loads (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, p. 7; Allcock and Wolverton, JCP, Exh. JCP-3, p. 3). BPA's final forecast of BPA Utility Type loads has used more recent data than either the initial forecast or any forecast suggested by the parties (Lenzen, BPA, Exh. BPA-59, p. 2). This updated data should reflect the most recent DRI projections as to the duration of the current economic recession and the anticipated recovery. Therefore, I believe that the final forecast of BPA Utility Type loads reflects the most recent DRI economic information and as a result will most reliably predict future electricity consumption for these loads.

The BPA Utility Type loads for the final forecast are lower than the initial forecast. The final forecast also employs two ARIMA models; however, the models were combined statistically rather than mathematically as was done for the initial proposal. I have determined that the combined forecast used in this final proposal incorporates updated projections of future economic conditions to reasonably project future energy consumption for BPA Utility Type loads.

The Joint Customer Proposal (JCP) expressed concern that BPA's forecast of BPA Utility Type loads did not explicitly account for price and economic effects, and urged that BPA use the JCP forecast of BPA Utility Type loads rather than the combined ARIMA forecast (Allcock and Wolverton, JCP, Exh. JCP-3, p. 3). This suggestion, while theoretically valid, was not practical because BPA had neither the time nor the data available to conduct a study of this magnitude for this rate proposal. Additionally, the record reflects that the JCP's forecast for BPA Utility

Type loads was not statistically estimated or empirically derived (TR. 2209-2212). There is evidence in the record that forecasts such as the JCP's which are not statistically estimated should not be relied on as the only forecasting model (TR. 4404).

However, BPA did develop a simplified econometric equation, as evidenced in TR. 4396, that is similar in structure to that proposed by the JCP, and used it implicitly as a verification of the final ARIMA forecast. On the basis of this verification, I have determined that the final ARIMA forecast of BPA Utility Type loads represents a reasonable statistical estimate of regional electricity consumption for this rate filing in light of the current recession, anticipated recovery, and expected average retail price increases.

2. DSI Loads

Forecasts of DSI loads customarily have been based only on Contract Demands contained in each individual industrial customer's power sales contract with BPA. These contracts obligated BPA, for all planning purposes, to include maximum contract amounts able to be supplied in forecasts of DSI loads regardless of operating experience, even though historically the DSI's have not 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 initial rate proposal, BPA based its DSI load forecast on projected operating demand information obtained from the DSI's in the form of a memorandum from Bob Gillette to BPA's Power Manager dated September 17, 1981 (Exh. BPA-9, Attachment 4). During the rate hearings, some of BPA's industrial customers requested that BPA allow them to reduce their previous requests. On May 6, 1982, BPA's Power Manager sent a letter to DSI customers requesting a final forecast of their operating demands for the period from July 1982 through June 1983 (Pollock, BPA, Exh. BPA-61, Attachment 2).

During rebuttal testimony, BPA indicated that it intended to use this final forecast of operating demand for the first 9 months of FY 1983 and the operating demands contained in the Gillette memo for the last 3 months of FY 1983 (the 9 month and 3 month split conforms the fiscal year to the July 1-June 30 operating year) (TR. 4664-4666). The DSI representatives noted during the hearing and in their legal briefs, that this represented a significant increase in projected loads between June and July 1983. They argued that it was unreasonable to assume that their loads will increase as dramatically as BPA's forecast suggests on July 1, 1983, and that a forecast of DSI loads using only these operating demands may be higher than could be reasonably expected (TR. 4499-4505; TR. 4664-4667).

After reviewing these arguments and current economic information on the situation facing the industries, I have decided that it is reasonable to reduce the projected total DSI load from that presented by BPA in rebuttal testimony (Pollock, BPA, Exh. BPA-61, Attachment 1, pp. 11-14). For this final proposal, the firm portion of the DSI load, defined as 75 percent of the operating demand level, is the same as that presented by BPA in rebuttal testimony, but I have decided to reduce the interruptible portion of their loads from that submitted by BPA in rebuttal testimony, to 50 percent of the first quartile for the entire 12 month period.

I assumed that the DSI's as a whole will take 50 percent of their top quartile adjusted operting demands. This assumption recognizes that some DSI's are likely to operate at or close to their operating demand but also reconizes, in view of the statements in the record concerning their economic circumstances, that others may curtail to, at, or below 75 percent of their operating demands during some part of 1983. In light of this, I believe that it would be unreasonable to assume the DSI's, as a class, would seek to place a load on BPA equivalent to their full operating demands. There was little evidence in the record to permit me to estimate, with any precision, the portion of the top quartile the DSI's would seek to have served in the aggregate. Therefore, I simply assumed that there would be an average, as a class, between some industries at 0 percent service and some at 100 percent service to the top quartile. I therefore arrived at 50 percent as being midpoint of the range of possibilities, an estimate that is reasonable in my judgment. The reasonableness of this estimate was validated by DSI aggregate loads in the month of July 1982, the first month the adjusted operating demands were in place. During July, the operating level of the DSI's as a class included 45 percent of the interruptible portion of the operating demand. This actual experience, during a period of plentiful and low cost energy, provides additional validation of the 50 percent assumed service to the top quartile.

I believe that this decision reduces the overall level of service that BPA expects to provide to its DSI customers to a more reasonable level that is consistent with current economic conditions. However, this decision does not in any way reduce BPA's obligation to provide an increased level of service to its industrial customers if their recovery from the current economic situation is faster than this forecast anticipates.

Certain DSI's may argue that BPA's assumed service to the top quartile is to be "based upon the Administrator's projected ability to make power available" to the DSI's, and not also upon the Administrator's projected estimate of the DSI load for the rate period. Were I to adopt such a view of Section 7(c)(1)(A) of the Regional Act, it would result in a lower DSI rate. This is because since I adopt a uniform DSI rate, the more top quartile service I assume (which is assigned costs lower than exchange costs) the lower the average cost per unit of consumption. However, I reject this limited reading of Section 7(c)(1)(A) for several reasons.

First, the argument totally contradicts the position the DSI's took for purposes of estimating overall DSI load (TR. 4500-4505; 5910-5912). They suggested that it was inappropriate to forecast what is permissible under the contracts without looking at what the projected load would be. Such a proposal to project less DSI load would have the effect of assigning less resources to serve the DSI load and allocating less program and transmission costs to serve that load. Certainly with the surplus resources BPA has, it would have the ability to serve total DSI contract demand. Counsel for DSI's argued BPA should not even project that the DSI's would use their full opertaing demands to project DSI loads for cost allocation.

To base the DSI's rate on the assumed continued level of DSI curtailments for purposes of cost allocation for the bottom three quartiles of DSI service and then using reverse logic to assume a high level of service to the DSI top quartile because I am <u>able</u> to provide such a level of top quartile service would tend to lower the overall rate for DSI's, but would also greatly increase the risk that BPA would have unrecovered costs because the DSI top quartile loads would not materialize. I recognize that this forecast may have the appearance of unfairness for DSI's who do operate near their operating demand. However, the only solution to this intraclass equity problem would be a two-part rate, an option vigorously opposed by the DSI's.

The second reason I reject using only the "projected <u>ability</u>" argument concerning Section 7(c)(1)(A) is because it must be read in conjunction with my obligation to set the DSI rate "at a level which the Administrator estimates will be sufficient to recover the cost of the resources the Administrator determines are <u>required to service such customers' loads</u>. . ." I conclude that my obligation is to make a projection of the loads I anticipate that I will serve based on: (1) my projection of what the DSI's would like to have served, and (2) my ability to meet those projected loads. To set the DSI overall rate based upon only my projected <u>ability</u> to serve loads that I do not expect to exist would assign costs to the DSI's that no competent evidence in the record indicates I would have any assurance of recovering.

3. <u>IOU Net Requirements</u>

BPA's initial forecast of IOU net requirements was based on data provided by the IOU's. Subsequent to the initial forecast, the IOU's informed BPA not to assume any IOU net requirements placed on BPA during the test year because of the uncertainties associated with the IOU contracts and the structure of the NR-2 rate (Allcock and Wolverton, JCP, Exh. JCP-3, p. 12; TR. 2237). Therefore, for cost allocation and revenue purposes, I have determined that BPA should assume that there will be no IOU net requirements placed on BPA during the rate period. However, because of the uncertainty in this regard, I directed that the NR-2 rate be designed to accommodate the loads of any IOU's that decide to contract with BPA.

4. <u>Generating Public Agency Firm Transfers</u>

For the initial forecast of Generating Public Agency Firm Transfers, BPA relied on information obtained from the Northwest Power

Pool (NWPP) and the Pacific Northwest Utilities Conference Committee (PNUCC). BPA regularly reviews this information under long-standing power sales contracts with these agencies. The PPC stated that this initial forecast was not adequate (Baxendale, PPC, TR. 323). Following this original forecast, more recent information about Generating Public Agency Firm Transfers became available from the NWPP and the PNUCC (Lenzen, BPA, Exh. BPA-59, p. 2). This final forecast of Generating Public Agency Firm Transfers has been updated to include this more recent information.

5. Residential Exchange Load

The Regional Act and associated exchange contracts provide that Pacific Northwest utilities may exchange with BPA an amount of power equal to a fixed proportion of their residential load at their average system cost for an equal amount of BPA power at BPA's priority firm power rate. In the initial proposal, BPA projected that the investor-owned utility residential exchange loads would be 2,741 average megawatts and the public agency residential exchange load would be 510 average megawatts. This projection of IOU exchange load was obtained from the IOU's, while the public agency residential exchange load estimates were developed by BPA. The public agency exchange loads were based on load information developed for the initial rate proposal and the assumption that utilities with a net benefit of greater than $3,000 per year would elect to participate in the residential exchange program.

During the rate hearings, BPA was informed of a more recent projection of IOU exchange loads, reducing the loads by approximately 40 average megawatts. I conclude that it is appropriate to use the revised residential exchange loads of the IOU's as presented in BPA's rebuttal testimony (Revitch, BPA, Exh. BPA-68, Attachment 1, p. 1). The revised residential exchange loads presented by BPA in rebuttal testimony differ from the figure developed by the IOU's (i.e. 2701 average MW's), because of more recent information which BPA explained during rebuttal testimony.

In addition, for the public agency residential exchange load some parties suggested that BPA should assume a net benefit threshold significantly greater than $3,000 per year (Allcock and Wolverton, JCP, Exh. JCP-3, pp. 10-12). They based this suggestion on estimates of the costs required to develop average system cost submissions.

The public agencies have requested, as part of a settlement in a suit brought against BPA concerning provisions of the offered Power Sales Contracts, that BPA offer to enter into Transmission Service Agreements (TSAs). These TSAs would provide the public agencies with transmission facilities the net benefit they would have received if they had participated in the exchange. BPA has agreed to offer Transmission Services Agreements, pending the implementation of the settlement of contractual disputes. I have reviewed the record as it pertains to the public agency exchange loads and have concluded that it is reasonable and appropriate to assume that a settlement will be reached in the contractual disputes and that BPA will offer Transmission Service Agreements in FY 1983

(Melton, BPA, Exh. BPA-62). Thus, I assume there will be no public agency exchange loads, and that the question of the $3,000 level of benefits threshold is irrelevant.

C. Hydroelectric Resources

Following completion of the load forecast, resources necessary to meet that load are determined. These resources include the Federal hydroelectric resources, firm purchases, and other resources which are already contracted for and available to serve BPA's expected firm load obligations. Hydroelectric studies are completed first to determine the portion of the load which can be met with these resources. Other resources are then added as needed to produce a load/resource balance. Over the 20-month critical period for which the load/resource studies were developed, BPA has an excess of firm resources of approximately 650 average megawatts. This estimate of firm surplus differs from that derived by the JCP (Allcock and Wolverton, JCP, Exh. JCP-3, Attachment B). New reduced load forecasts and reduced resource purchases primarily account for the difference in the firm surplus. The assumptions and methodology which produced the estimate of the firm surplus are described below. Thus, BPA has a firm surplus which is available for marketing to utilities in the Northwest, or if the resource is not needed in this region, to utilities outside the region.

For the initial rate proposal, BPA ran a series of hydroelectric power planning studies. These hydro regulations were used to provide estimates of BPA firm and nonfirm power. The initial studies, developed late in 1981, were based on a 42-month critical period. They covered the West Group Area as defined by the Pacific Northwest Utilities Conference Committee (PNUCC) and were run with 40 years by month of continuous streamflows (simulating 40 different reservior refill conditions). DSI top quartile loads were assumed to be served with a combination of 1 billion kilowatthours of shifted firm energy load carrying capability (FELCC), 800 million kilowatthours of advance energy, plus service from flexibility and nonfirm energy. Minimum flow requirements to allow downstream migration of fish were incorporated into the studies. Thermal resources in the initial study assumed to meet Federal load included 12 percent of Centralia, 50 percent of Hanford, 30 percent of Trojan, and power purchases from Weyerhaeuser/Longview Fibre for the entire 42-month critical period. Supply System plant 2 was included during the latter part of the critical period.

In the initial study, displacement of the Weyerhaeuser/Longview Fibre power purchases was made whenever possible after service to the DSI top quartile load. Also, water was stored in Federal reservoirs above the energy content curves (minimal reservoir levels to protect firm loads and refill) to enhance fish flows and to improve nonfirm service to top quartile loads during the January-June period.

For the final rate proposal, numerous changes have been incorporated (Pollock, BPA, Exh. BPA-61, pp. 8-11). The hydro regulations were run with the reservoirs starting full in each of the 40 streamflow conditions. At the time the studies were developed, the best estimate was that the system would refill by July 31 of this year, which subsequently has been verified. Also, the studies were run with the latest estimates of loads and resources submitted for the Pacific Northwest Coordination Agreement 1982-83 modified regulation, for an area slightly different from that defined by the PNUCC West Group Area. Therefore, the hydro regulations used in the final rate proposal more closely resemble the study used in the Coordination Agreement planning process which will apply to BPA's operation. Also, the length of the critical period under that agreement is now 20 months, the same as that determined in the modified regulation. Finally, the amount of DSI top quartile load served from shifted FELCC has been reduced to reflect new DSI requirements.

For the months September through December, the final studies show that DSI top quartile loads will be served by 180 million kilowatthours of shifted FELCC, 800 million kilowatthours of advance energy deliveries, and with nonfirm energy whenever possible for the remainder of the year.

Contracts for the purchase of 12 percent of Centralia and Weyerhaeuser/Longview Fibre are assumed to extend only through June 30, 1983. This is consistent with the JCP which recommended that these resources should be excluded from the analyses beyond the contract date, because they were not needed for the entire critical period. In addition BPA did not withdraw Hanford to serve BPA loads, and therefore, it has been removed as a resource during the rate year.

The results of the hydro regulation studies which include purchase of Centralia and Weyerhaeuser/Longview Fibre, for three-fourths of the rate year, and purchase of programmatic conservation produce a firm surplus of approximately 650 average megawatts over the 20-month critical period. Surplus was shaped out of the spring and into the remainder of the year, except it was not shaped out of the spring fish migration period.

Following completion of the hydro regulation, the Pacific Northwest Coordinated System Federal system analysis was prepared to determine Federal nonfirm energy availability. Nonfirm energy for the purpose of this analysis is the extra energy produced from average streamflows above critical period streamflows. The analysis of nonfirm is to: (1) determine the availability and amount of this "above critical" energy; (2) establish the amount used in meeting BPA's firm loads; and (3) determine the remaining amount available for marketing as nonfirm. In this study BPA has used the production of energy beyond critical water capability, to maximize the displacement of expensive thermal power purchases and operation of high incremental cost resources.

Parties in this proceeding raised questions concerning BPA's displacement policy and service to the top quartile (TR. 581-94, 650-53, 658-65). Two issues were raised: (1) whether BPA would displace thermal purchases before serving the top quartile of DSI loads; and (2) what impact the Ninth Circuit Court of Appeals' decision in Central Lincoln Peoples' Utility District v. Johnson, No. 81-7561 (9th Cir. 1982) (Central Lincoln I) would have on marketing of nonfirm energy to public agencies.

I have decided that for the purpose of developing rates, the hydro regulation study should assume displacement of Federal purchased power before any service to the DSI top quartile load. The decision does not pre-decide the displacement policy issues that are being determined through the rulemaking that is presently underway (47 Fed. Reg. 31307, July 19, 1982). This decision also does not pre-decide operation of the Federal system. This is simply an assumption for ratemaking purposes. This decision does not jeopardize service to the DSI top quartile. Due to the present level of economic activity in the region, coupled with the projections for overall DSI loads assumed herein, BPA should be able to meet any top quartile service the DSI's require.

Second, to conform to Central Lincoln I, although the court's decision is stayed pending the outcome of petitions for rehearing, the delivery of nonfirm energy to the top quartile will be subject to preference and priority to be given to public bodies and cooperatives. An additional concern is the storage of water for fish flush. The study continues to include storage of water in coordinated system reservoirs above energy content curves to enable the system to provide instream flows for fish migration during late spring.

The basis for the forecast of nonfirm revenues is the Secondary Energy Analysis (SEA). The SEA forecasts sales by month for 40 historical water conditions to determine average sales. The result of this analysis is a forecast of BPA sales of nonfirm energy.

D. Economic Shift of FELCC

A shift of Firm Energy Load Carrying Capability (FELCC) as defined in the Pacific Northwest Coordination Agreement is essentially the movement of planned reservoir draft from a month or year late in the critical period to make that draft available in an earlier month or year. The availability of this additional reservoir draft provides the capability to generate additional energy from hydro and therefore displace what would otherwise be a higher incremental cost purchase. This shift of FELCC is permitted, from a firm load carrying standpont, by the availability of firm generation to meet load in the latter period of the critical period if this turns out to be needed.

Based on the evidence in this record I believe that a shift of FELCC would not be prudent given the resource surplus which BPA currently projects it will experience. Furthermore, I find that a shift of FELCC during this rate period would not be of the type contemplated by the economic shift agreement of October 1, 1981 (Exh. IO-1). Counsel for IOU's conceded at oral argument that such a shift is not required by the agreement (TR. 6086).

I also find that the purchases of Centralia and Longview Fibre/Weyerhauser were consistent with the FELCC shift letter because they were intended to place BPA in long-term load/resource balance at a time when BPA believed, based on its then available load forecast, that it would face a long-term deficit. I adopt the views of BPA counsel regarding such purchases as found on pages 22-29 of the Memorandum of Bonneville Power Administration Counsel.

On the other hand, I believe that, consistent with the economic shift letter of October 1, 1981, (Exh. IO-1) a shift of FELCC can prudently be used to reduce expensive resource purchases. Counsel for PP&L, in oral argument and in his opening and reply briefs, points out five barriers which he believes BPA has imposed which may cause BPA to never shift FELCC. PP&L's witness in the proceedings, and PP&L's counsel invited BPA to take two steps to show its good faith regarding the FELCC shift letter. First, they suggested, (although as indicated, not required by the FELCC shift agreement,) that BPA shift FELCC during the rate period in order to produce additional resources which could be sold for the benefit of the 7(f) pool. Opening brief of PP&L at 3. Though I conclude that I can market BPA's available surplus during the rate period, given the potential limitations in that market and the size of BPA's firm surplus, I do not believe that it would be prudent to shift FELCC to create additional surplus. Furthermore, there seems little to support such a shift this year when the shifting of FELCC would not be necessary to serve 7(f) loads in lieu of expensive thermal purchases since the IOU's and JCP suggest that there will be no, or very small, 7(f) loads placed on BPA during the rate period (TR. 2412), and since the NR-2 rate which would apply to 7(f) loads does not include any expensive thermal purchases..

Counsel for PP&L suggested an alternative proposal for BPA to demonstrate its good faith in connection with the FELCC shift agreement, a demonstration of how five barriers identified could be removed. BPA has analyzed those five perceived barriers to the shift as follows:

<u>Barrier #1 - Economic Barrier</u>:

Whether an economic shift in FELCC is indeed economic depends on the comparison of the fixed and variable costs of the resource which would be displaced (not purchased) as the result of the shift of FELCC, and the cost of securing capacity of a resource to back up the shift of FELCC in later years of the critical period, together with the energy costs which would likely be incurred over time from operating the "back up" resource in years when reservoirs did not refill and BPA was indeed in a critical period. The likely energy charge would be determined by multiplying the probability of needing to operate the resource times the cost of the energy. As indicated in the testimony of Ralph Deesen (Exh. IO-14) BPA conducted a study of shift of FELCC for the rate period in order to determine the economics of the shift of FELCC.

Counsel for PP&L suggested that BPA should not need to conduct the types of studies which it conducted in late 1981 and early 1982 to determine the economic feasibility of the economic shift. Counsel suggested that BPA should be willing to shift if its customers are willing to bear the cost of the risks in order to achieve short-term benefits. This assumption could result in an unacceptably wide swing in the rates that we are concerned would not be anticipated without a suitable analysis. However, based on the testimony of Ralph Deesen (ICP, Exh. IO-14, p. 3-4) I believe there is likely to be an economic advantage to a shift of FELCC when BPA's alternatives to such a shift of FELCC to meet firm loads are expensive thermal resource purchases.

Barrier 2 - Availability of "Backup" Resources

BPA has firm load obligations. The FELCC shift is proposed to offset short-term resource purchases which would give BPA the assurance of meeting firm load obligations. Therefore, in the economic shift agreement, BPA conditioned an economic shift of FELCC upon having an assurance of sufficient backup resources to meet BPA's firm loads should critical water develop during the out years of the critical period from which the FELCC is borrowed. BPA will undertake an economic shift of FELCC if there is reasonable assurance that backup resources are available to BPA from either the Northwest or the Southwest. Under current circumstances, BPA is in a unique place in time: (1) BPA does not know what the IOU's loads will be in the current or ensuing years; (2) BPA does not know what the DSI's loads will be because of economic conditions; and (3) BPA does not know what its fisheries obligations will be under the Regional Act; all of which have a very significant impact on our load/resource balance. Within the next few months, each of those contingencies will likely become much clearer. In future years, we do not believe that we will be faced with unpredictable large swings in loads caused by potential changes in contract rights to place loads on BPA or the large resource swing associated with fishery obligations. Thus, BPA should be in a better position to access the availablilty of resources, and if ample resources appear available to back up a shift of FELCC, BPA may decide it does not need to obtain firm resource capacity options for the period the FELCC was shifted from, if Northwest and Southwest resources are plentiful. This, naturally, would enhance the economics of an economic shift because if BPA was not obligated to pay for standby capacity from high cost resources, the cost of shifting FELCC would be greatly reduced. In light of the magnitude and duration of current projected resource surplus, we believe BPA is in a good position to develop an inventory of available resources to use as backup for a shift of FELCC. Customer assistance in the development of such an inventory would help to assure that BPA could move quickly and confidently in future years when BPA's surplus is gone and BPA is faced with potential short-term expensive thermal resource purchases to meet its firm load obligations.

Barrier #3 - Fisheries Concern

The Pacific Northwest Electric Power and Conservation Planning Council (Regional Council) is in the midst of developing its fisheries plan for the region. Although the impact such plan will have on the operation of Federal resources is uncertain, it is presumed the plan will have a negative impact on firm energy capability of the Federal system. However, the plan will soon be known. In future years when an economic shift of FELCC might be attractive, the fishery obligation will already by figured into BPA's resource planning. Furthermore, BPA believes that substantial capability exists within the Federal system to allow for reasonable fisheries enhancement, protection, and mitigation and at the same time to conduct a shift of FELCC if it is indeed economical and the shift is not prohibited by the fisheries plan of the Regional Council or some other requirement imposed by statute, regulations or court order, or other requirement of law.

Barrier #4 - Renewable Acquisition Barrier

BPA during the past year has been faced with a temporary phenomenon resulting from its substantial new responsibilities to acquire and develop renewable resources as a second priority resource under the Regional Act. As BPA develops a better inventory of available renewable resources, and prioritizes those resources from the perspective of cost effectiveness, BPA will be in a better position to attempt to integrate such resources into its long-term load resource balance.

PP&L counsel identified what he believed was a separate barrier to BPA's conducting a shift of FELCC believing that BPA would hypothesize some amount of renewable resource acquisition to overcome any potential resource deficiency, avoiding any load resource imbalance, and thereby avoid an economic shift of FELCC. As indicated above, as BPA knows with some specificity which renewable resources it will be purchasing, it will know more precisely what its load resource balance is and will not include unsubstantiated renewable resources in meeting that load resource balance. Thus, if available cost-effective resources do not put BPA in load/resource balance, the amount of deficit for which a shift is desirable will be clear.

Barrier #5 - Definition of Short-Term Resource

The fifth barrier to the economic shift of FELCC identified is perhaps the area of greatest controversy related to BPA's shift of FELCC. Counsel for PP&L maintains that any resource purchased for less than 5 years was a "short-term" purchase within the contemplation of the economic shift agreement (Exh. IO-1) and therefore should be the type that would be displaced by an economic shift of FELCC. In particular, of course, counsel points to the purchase of the Centralia plant for a period of 18 months, with a renewal option, as being a type of resource which should have been displaced with a shift of FELCC.

As BPA witness Pollock stated again and again, the purchase of the Centralia plant was made in contemplation that it would be acquired for a long-term period. However, given the uncertainties with respect to loads and resources which I faced at the time I made the commitment on Centralia, I determined that the relatively short-term 18 month option on Centralia plant, with an option to renew, was a reasonable way of balancing out the uncertainties of the load forecast with what I believe would have been a long-term cost effective resource should it have appeared necessary to meet my firm loads. It turned out to be prudent that we did acquire Centralia for a short term with an option to renew, since BPA has a resource surplus even without Centralia. I will assume for ratemaking purposes that I will not renew my purchase of the Centrailia project and have developed my rates accordingly. Nevertheless, such renewable agreements may be prudent in the future.

On the other hand, I do not believe it would be prudent to make short term acquisitions to put BPA in load/resource balance, when such short term resource acquisitions might be combustion turbines or other very expensive thermal resources, the type of resource which would not be used to meet the long-term load/resource balance. When faced with such purchases, I will test them against the economics of a shift of FELCC and, if economic, will vigorously pursue an economic shift of FELCC to avoid such purchases as was contemplated by my October 1, 1982, letter agreement.

Based on the foregoing analysis, I reaffirm my commitment to an economic shift of FELCC when it will benefit BPA's ratepayers.

E. Conservation and Resource Acquisitions

The JCP recommended a reduction in costs of acquisitions and conservation reflecting the surplus expected in FY 1983 (Opatrny and Deesen, JCP, Exh. JCP-4 and Sunday, JCP, Exh. JCP-5). Although not a specific rate issue, I felt that because BPA has a firm surplus for the rate year and for several ensuing years beyond the rate year, it was necessary to develop a general short-term resource policy which would address principles to guide resource acquisition decisions during a surplus period. The focus of this policy has been directed toward cost-effective resources which will minimize BPA cash flow requirements and adverse environmental impacts, while yielding the lowest cost mix of resources to meet future deficits (Pollock, BPA, Exh.BPA-61, pp. 5-6).

1. Near Term Resource Policy

Under the near term resource and conservation policy resources must minimize BPA cash flow requirements in excess of the incremental revenue that BPA receives from surplus power sales, and must have the following characteristics:

(1) A levelized monetary cost no greater than 35 mills/ kilowatthour in constant 1982 dollars, including transmission, waste disposal, and end-of-cycle costs (conservation will be given a 10 percent cost advantage); and

(2) The bulk of its power or savings produced in the forecasted deficit periods; and

(3) Several years required to realize full resource potential; or

(4) A delay or loss of the resource to the region on a long-term basis would result in an increased total system cost associated with the resources used to meet forecasted loads (Pollock, BPA, Exh. BPA-61, pp. 5-6, TR. 5062).

The above conditions apply to all acquisition activity. In addition, BPA would acquire generating resources in the rate year under one of the following arrangements:

(1) An acquisition under which BPA takes delivery of power beginning in the late 1980's or later.

(2) A long-term acquisition under which delivery of power would begin in the early to mid-1980's where nominal cost, during the surplus period, is not substantially in excess of incremental revenues which could be recovered from surplus power sales.

(3) Purchase of an option to acquire a resource, to be exercised when needed to serve BPA loads, at a contractually established price.

Additional policy elements in the specific area of conservation resources include:

(1) The Regional Act committed BPA to treating conservation as a resource and making conservation the first priority in meeting load requirements. BPA counsel advised me that the Regional Act directs me not to reduce conservation efforts, even if previous resource acquisitions provide BPA with sufficient resources to meet contractual firm power obligations (16 U.S.C.A., 839d(b)(3)). This obligation must be balanced with my obligation to keep rates as low as possible, consistent with sound business principles. In response to the near-term surplus, resource acquisition and conservation activity will be lower than previously projected (Pollock, BPA, Exh. BPA-61, pp. 1-2).

In the fall of 1981, BPA offered conservation acquisition contracts to utilities for the implementation of five conservation programs: residential weatherization, showerflow restricters, water heater wraps, street and area lighting, and commercial lighting and water heating. The utilities began offering these programs to end-use consumers soon thereafter.

(2) BPA is commited to continuing these existing programs at their current levels. The savings projected to result from these programs have been incorporated in the load forecast. Market analysis indicates that successful implementation of conservation is dependent on consistent program offerings, including the offering of consistent incentives (Hickok and Whitney, BPA, Exh. BPA-63, p. 2; TR. 5066-67) Because of the dispersed (to large numbers of individuals) nature of these programs, they cannot simply be turned on and off to match varying load/resource balances. Breaking the commitments for these programs would

do more long-term harm to the overall conservation effort than is warranted by a short-run cost reduction.

(3) In order to have conservation savings available in future deficit periods, it is necessary to begin new conservation activities now (TR. 4950). However, new conservation programs must be consistent with the BPA near-term resource policy. This policy as it applies to conservation is: (1) Measures should be added now that require "ramping," i.e., several years to reach full market penetration. If programs can be implemented closer to the deficit period and still produce timely energy savings at the same cost, we will defer their implementation. (2) New conservation programs should be started only if the bulk of their savings is in the deficit period. Therefore, new cost-effective conservation programs should be implemented only if they provide long-term savings. (3) Special consideration will be given to "cost opportunities" where failure to buy conservation savings now would preclude having this resource available in the future and would cause BPA to pay more for resources when they are needed.

2. Resource Acquisitions

In the JCP the customers recommended that BPA limit its resource acquisitions, other than Centralia and Weyerhaeuser/Longview Fibre for three-fourths of the year, to the 16 megawatts at a cost of $5.2 million associated with the Idaho Falls project (Opatrny and Deesen, JCP, Exh. JCP-4, pp. 2-4). I adopted the JCP recommendation relative to treatment of Centralia and Weyerhaeuser/Longview Fibre. In addition I have included $14.6 million for various resource acquisitions (Pollock, BPA, Exh. BPA-61, Attachment 3) which we expect to make in accordance with our near-term resource acquisition policy described above. The four programs to be funded are: Small Renewable Resources, Preconstruction Funding Guarantee, Investigation and Assessment of Resources, and Billing Credits.

I have assumed that any acquisition made and any billing credit granted would reflect a 1982 and 1983 nominal cost of 35 mills per kilowatthour. This is a maximum amount based on the near-term resource policy and the likelihood of marketing the energy outside the Pacific Northwest Region during a period of regional surplus. In addition, new acquisitions for 1983 for the rate filing are based on an assumption of 25 average megawatts acquired in FY 1982 being carried into FY 1983 plus an additional 25 meagawatt acquisition for one-half year in FY 1983.

For small resources, the new acquisitions are based on a 10 average megawatts acquired for one half a year. This is our expectation of the total amount to be acquired during the year. In fact, the proposed price limit of 35 mills in nominal dollars will probably contribute to controlling the pilot program to a considerable degree, perhaps below the 10 average meagwatt level in terms of what might be available.

For billing credits, expenditures are estimated on the basis of 10 average MW for one half a year. This is an estimate only because the billing credit policy has not been finalized. I have treated the billing credit costs in the same manner that I have treated other resource acquisition costs in the rate development process.

The preconstruction study guarantee program will be a pilot program with no expenditures during FY 1983. It is expected to be a commitment to pay the principal costs and associated interest for a project of an eligible sponsor of a nonmajor renewable resource in the event I do not acquire the resource. If I acquire a resource after the resource goes through this program, the costs of the preconstruction studies will be included in the cost of financing the construction of the project.

3. <u>FY 1982 and 1983 Conservation Expenditures</u>

In the initial proposal BPA projected conservation expenditures of $164 million in FY 1982 and $362.7 million in FY 1983 (Whitney, BPA, Exh. BPA-13, p.1). The JCP recommended that BPA funding for conservation in FY 1983 be reduced to $178 million and that BPA's spending for conservation in FY 1982 would only be $64.6 million dollars (Sugden, JCP, Exh. JCP-5, Attachment D). The JCP asserted the lag in program implementation experienced by BPA in FY 1982 would continue in FY 1983 and BPA had not taken that information into account in making program estimates (Sudgen, JCP, Exh. JCP-5, p. 3). Also, the JCP recommended reduced funding in FY 1983 for two programs, Solar Heat Pump Water Heater and Section 6(a) Acquisitions, to reflect BPA's new load/resource balance and near term surplus. Other customers also suggested that BPA conservation expenditures be reduced for both FY 1982 and FY 1983. On the other hand, California Energy Commission (CEC) urges BPA to spend more money on conservation and sell more surplus power, capacity and energy to California (CEC Opening Brief, p. 10).

In response to the parties critiques of conservation expenditures and as part of BPA's conservation planning process, I reviewed BPA's conservation programs in light of BPA's new load/resource balance and the actual rate of program implementation experienced to date. In rebuttal testimony, BPA staff recommended reducing the conservation budget for FY 1983 to $279 million, with $253 million financed through treasury borrowing (Hickok and Whitney, BPA, Exh. BPA-63, Attachment 1; TR. 5062). In addition, BPA staff recommended reducing FY 1982 expenditures projections to $95.9 million (Hickok and Whitney, BPA, Exh. BPA-63; Exh. BPA-77). After reviewing the conflicting suggestions for conservation expenditures, I have determined the level of conservation activity in FY 1983 which I believe will impose the least cost to the region's ratepayer over the planning period. The revised projection for FY 1983 conservation expenditures is $284.4 million. This estimate includes a 68 percent reduction in the Solar Heat Pump Water Heater Program to reflect the extension of program life to 10 years. In addition, the Section 6(a) Acquisitions Program has been reduced by 75 percent in FY 1983 in response to BPA's near-term surplus conditions. Approximately 77 percent of the $284.4 million is for funding of existing programs which are already underway (Weatherization, Street/Area Lighting, Water Heater Wraps, and Commercial Lighting and Water Heating). A continued lag for these programs in 1983, as recommended by the JCP, is not substantiated since I believe the lag is principally in the startup phase.

I also have reviewed BPA's FY 1982 conservation program implementation over the first eight months to determine a reliable estimate of the level of expenditures expected for FY 1982. As a result of that analysis, I find that the appropriate projection for BPA conservation spending in FY 1982 is $68.2 million.

Conservation program energy savings have been revised to reflect the new FY 1982 and 1983 spending level projections (Exh. BPA-77). I estimate that BPA will save energy at an annual rate of 178.8 megawatts from all conservation measures installed under a BPA program through the end of FY 1983. Expenditures at this level to achieve the projected savings are cost effective, when measured against the previously articulated near-term resource policy.

2. <u>Fuel Switching</u>

The representatives from the region's natural gas industry expressed concern that one of BPA's proposed programs, the New Home Construction Program, will induce electrical load through the switching of fuels from non-electric to electric sources (TR. 491, 506-38, 4968-89). We share this concern, and BPA currently is conducting an analysis to evaluate the issue of fuel switching. BPA plans to offer only a pilot program in late FY 1982 or early FY 1983 to evaluate the impact of an incentive program for electrically heated homes on the market for other fuels.

F. <u>Pre-Regional Act Contract Rates</u>

The City of Seattle argues that since it is purchasing power from BPA under existing pre-Regionl Act contracts, no costs associated with the Regional Act can be allocated to its rates (Opatrny, SCL, Exh. CL-1). The City contends that the Administrator must develop two sets of rates for power sales, one for sales under post-Regional Act contracts and a second separate set of rates for sales under pre-Regional Act contracts, citing Section 10(b) of the Regional Act (SCL Brief at 4 et seq.). BPA's existing contract with the City of Seattle contains a section governing the "Equitable Adjustment of Rates." This section is virtually identical to one contained in the power sales contract of another BPA customer, and litigated in <u>Montana Power Co. v. Edwards</u>, No. 80-842 PA, (D. Ore, May 18, 1981) (not yet published). In that case, plaintiffs argued among other things, that a rate schedule change instituted by BPA and approved on an interim basis, constituted a breach of their contracts with BPA and amounted to a "penalty." The court disagreed and found that "[t]he fact that plaintiffs will have to spend more money for the power they receive under the contract is hardly a 'penalty.' The contracts contemplate rate increases, and <u>no provision addresses maximum rates</u>." <u>Montana Power</u> at 5.

Based upon the position I took last year regarding recovery of Regional Act costs from my DSI customers and consistent with advice of counsel, I conclude that the Regional Act empowers and directs me to carry out new obligations and my pre-Regional Act contracts give me the right to raise rates to carry out any program Congress directs me to undertake incident to my duties in marketing and transmitting power.

The City of Seattle even goes so far as to suggest that because they have not signed new power sales contracts, they should be able to avoid the costs associated with the Administrator's fish and wildlife enhancement responsibilities (Opatrny, SCL, Exh. CL-1, pp. 7-8). Through passage of the Regional Act, Congress has required the Administrator to expand his responsibilities, including fish and wildlife enhancement, conservation, resource acquisitions, and the exchange. As a natural consequence, the Administrator will incur additional costs in supplying power to his customers. Congress determined that there were regional benefits by the Administrator carrying out these expanded responsibilities. The City of Seattle and its customers will benefit from the Administrator carrying out these responsibilities and therefore the City of Seattle should be allocated an equitable share of the cost associated with these responsibilities as long as it chooses to purchase power from BPA.

Ms. Opatrny admitted during cross-examination that the City of Seattle is benefitting from BPA's conservation program since the City of Seattle has signed a short-term conservation contract and is receiving financing from BPA for eligible conservation programs (TR. 3146). Even if the City of Seattle were not itself to participate in BPA's conservation program, it could benefit from the existence of such a resource because the amount of power available when Seattle asked for a new contract to meet its requirements would be greater than the allocation to which it would have previously been entitled.

I find that the City of Seattle and all BPA ratepayers are obligated under both pre- and post-Regional Act contracts to pay those costs BPA lawfully incurs. Otherwise, I would be unable to meet my statutory repayment obligations. I adopt the views of my counsel and decline adopt Seattle's narrow view of the Regional Act. See Memorandum of BPA Counsel pp. 5-10 and Reply Memorandum of BPA Counsel pp. 4-9.

IV. Repayment Study

A. Introduction

As discussed in Chapter II of this document, BPA is required to set its power and wheeling rates so as to recover the cost to the Government of producing, purchasing, and transmitting electric energy. The adequacy of revenues from existing power and wheeling rates to meet this requirement is determined by a Power System Repayment Study.

The repayment policy as applied in the Repayment Study is designed to establish revenue levels that are sufficient to meet required payments for the cost of the Federal Columbia River Power System (FCRPS) and the costs of BPA's new responsibilities as defined by the Regional Act. The FCRPS consists of BPA which purchases, transmits, and markets power; and the generating facilities of the Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau). Each entity is separately managed and financed, but the facilities are operated as an integrated power system. Thus, the costs associated with each facility are combined and known as the FCRPS. BPA, as a power marketing agency for the FCRPS, has the responsibility to establish rates that will return sufficient revenues to cover all costs and obligations of the FCRPS on a timely basis.

BPA has a threefold objective in establishing the level of its power rates. Rate levels must be set sufficiently high so as to produce revenues adequate to recover power costs (Section 7 of Bonneville Project Act, Flood Control Act of 1944, Section 9 of the Transmission Act of 1974 and Section 7 of the Regional Act), but at the same time set sufficiently low so as to encourage widespread use of electric energy and provide the lowest possible rates to consumers (Flood Control Act , Section 9 of the Transmission Act as reaffirmed in Section 7 of the Regional Act). In addition rates must be set in accord with sound business principles (Flood Control Act, Section 7 of the Transmission Act, and Section 7 of the Regional Act).

Recognizing that many hydroelectric projects serve other purposes besides electric production, such as navigation, flood control, and irrigation, costs of Federal multipurpose dams are allocated to different purposes. Under the Bonneville Project Act, the Federal Power Commission (FPC) and now the Federal Energy Regulatory Commission (FERC), is charged with allocating the costs of the Bonneville Project. Legislation authorizing projects gives FERC responsibility for preparing cost allocations at the McNary project and the four projects on the Lower Snake River (Ice Harbor, Little Goose, Lower Monumental, and Lower Granite). Other project authorizations give the Secretary of the Army responsibility for developing cost allocations for the Corps of Engineers projects other than those where this responsibility has been assigned to the FERC. The Secretary of the Interior is responsible for approving cost allocations for projects constructed by the Bureau. BPA usually participates in the development of the cost allocations for all projects.

The cost allocation methods generally allocate the specific cost of each feature to the purpose it serves. For example, the cost of powerhouses, penstocks, and other specific power-related facilities are allocated to power, and the cost of navigation locks is allocated to navigation. The joint-use costs that remain unallocated after the specific costs have been allocated generally are divided among the various purposes served. The joint-use cost allocating formulas take into account the relative benefits produced by each function to assure that the allocations are made in an equitable manner.

With respect to the recovery of the cost of the transmission system, the Transmission System Act recognizes that the transmission system is used both for transmitting Federal power marketed by BPA and for wheeling non-Federal power. The Transmission Act requires that the recovery of the cost of the transmission system be "equitably allocated between the Federal and non-Federal power utilizing such system." This is to be done by appropriately balancing the wheeling rates with the transmission cost component included in the power rates.

Other statutory provisions concerning the repayment of power costs and the establishment of power rates are found in the Reclamation Project Act of 1939; Pub. L. 89-448, approved June 14, 1966, authorizing construction of the Grand Coulee Third Powerplant; and Pub. L. 89-561, approved September 7, 1966, which partially amended Pub. L. 89-448.

B. Administrative Development of Repayment Policy

The statutes are not specific with regard to the development of the repayment policy. BPA's repayment criteria were developed in the material submitted to the Secretary of Interior and the Federal Power Commission in support of BPA's rate increase in December 1965. The repayment policy also was presented to Congress in conjunction with consideration of the authorization of the Grand Coulee Third Power plant. The repayment policy was incorporated into the legislative history of Pub. L. 89-448, authorizing construction of the Grand Coulee Third Powerplant in June 1966.

The Secretary of the Interior has developed general principles, subsequently set forth in the Department of the Interior Manual, Part 730, Chapter 1, to guide repayment. These are:

> "A. Hydroelectric power, although not a primary objective, will be proposed to the Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operating and maintenance costs and interest, in accordance with the law."

> "B. Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment

within 50 years with interest that more accurately reflects the cost of money."

To achieve a greater degree of uniformity in the application of the repayment policy by all of the Department of the Interior power marketing agencies, the Deputy Assistant Secretary of the Bureau of Reclamation issued a memo on August 2, 1972, outlining (1) a uniform definition of when the repayment period for projects commences; (2) the method for including future replacement costs in repayment studies; and (3) a provision that the investment bearing the highest interest rate shall be amortized first, to the extent possible, while still complying with the repayment period established for each increment of investment.

A further clarification of the repayment policy was enunciated in a joint memo of January 7, 1974, from the Assistant Secretary for the Bureau of Reclamation and Assistant Secretary for Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the capital investment within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for operation and maintenance, purchased power, and interest. Also, the Transmission Act contains the proviso that rate levels be adequate to cover the interest and amortization on the bonds that BPA sells to the U.S Treasury.

On March 22, 1976, the Department of the Interior issued Chapter 4 of Part 730 of the Departmental Manual to codify financial reporting requirements for the Interior Department power marketing agencies. Included therein are standard policies and procedures for preparing power system repayment studies. The Department of Energy (DOE) has adopted the policies set forth in Part 730 of the Department of the Interior Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which subsequently was replaced by Order No. RA 6120.2 on September 20, 1979.

C. Regional Act Costs

The Regional Act expanded BPA's responsibilities in the region and required changes in the process and substance of BPA's rate development activities. Prior to the Regional Act, BPA allocated costs of resources from a single block, and designed rates to recover those costs from limited classes of customers. Now there are additional program and resource costs, and BPA's services extend to all classes of customers within the Pacific Northwest. The costs associated with the programs and other obligations of the Regional Act are included in the Power System Repayment Study.

D. Financing the Power System

The hydroelectric generating projects constructed by the Corps of Engineers and the Bureau of Reclamation are financed by appropriations enacted by Congress. The BPA transmission system was financed with appropriations through FY 1975. The Transmission Act placed BPA on a self-financing basis with authority to use its revenues to finance its operating costs, including purchased power, and to sell bonds to the Treasury to finance the construction of new transmission facilities. The Regional Act extended BPA's borrowing authority also by providing authority to sell bonds to the Treasury to finance BPA's new conservation programs. All FCRPS costs, whether financed by appropriations or bonds, including current BPA operating costs, are repayable from the FCRPS revenue requirement as established in the FCRPS Power System Repayment Study.

E. Repayment Policy Criteria

The repayment policy provides that BPA's total revenues from all sources be sufficient to:

1. Pay all costs annually of operating and maintaining the Federal power system.

2. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements and by acquiring resources, which include conservation.

3. Pay when due the interest and amortization on outstanding bonds sold to the Treasury.

4. Pay interest each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established for each generating project and for each annual increment of investment in the BPA transmission system.

5. Repay:

(a) each dollar of the power investment in the Federal generating projects within 50 years after the projects become revenue producing (50 years has been deemed a "reasonable period" as intended by Congress),

(b) each annual increment of transmission investment previously financed with appropriated funds within 35 years after it is placed in service (35 years is the approximate average service life of the transmission facilities, and hence a "reasonable period"), and

(c) the investment in each scheduled replacement within its service life up to a maximum of 50 years.

Such repayment shall be made by amortizing the investment bearing the highest interest rate first, to the extent possible, while still completing repayment of each increment of investment within its prescribed repayment period.

6. Repay the portion of construction costs at Federal reclamation projects that is beyond the repayment ability of the irrigators, and is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments on construction costs. These repayment periods range from 40 to 66 years with 60 years being applicable to most of the irrigation projects. Irrigation costs are repaid without interest. (Pub. L. 89-448 authorizes the payment of irrigation costs from revenues of the entire power system. This is

the so-called "Basin Account" concept. Pub. L. 89-561, approved on September 7, 1966, amended Pub. L. 89-448 to provide several limitations on the repayment of irrigation costs from power revenues recited above.)

The repayment policy provides that if BPA's revenues are not adequate to recover all amounts due in a given year, repayment of some costs must be deferred. The order in which the deferrals will be made is as follows:

(1) Amortization of the irrigation repayment assistance is deferred until the last year of its repayment period in all cases,

(2) amortization of power investment financed with appropriated funds,

(3) interest on power investment financed with appropriated funds,

(4) hydroelectric generating project operation and maintenance costs.

If further deferrals were imminent, BPA probably would have to request appropriations to continue its operations.

The repayment criteria provide that if interest and/or operation and maintenance payments are deferred, the amount deferred must be capitalized and amortized with interest prior to the amortization of investment. These deferrals are permitted by the DOE repayment policy only in unusual circumstances and for a short period of time.

F. Power System Repayment Study

The Power System Repayment Study compares the revenues and costs for the entire power system as established in the cost evaluation period over the remainder of the repayment period to determine the amount of amortization and interest expense for the cost evaluation period. In the Repayment Study, the estimated revenues are applied to cover each year's expense for (1) purchased power, (2) operation and maintenance, (3) interest, and (4) amortization of BPA's bonds. All remaining revenues are applied to the amortization of the power investment financed with appropriations and, in the years in which irrigation repayment assistance is due, to the amortization of the irrigation costs assigned for repayment from power revenues. The adequacy of the revenues to cover all of the repayment obligation is then determined by comparing the unamortized amount of each investment during each year of the study with the "allowable unamortized investment."

The allowable unamortized investment for any given year is the maximum investment that can remain unamortized in that year if the repayment periods established for each power facility are observed; that is, 50 years for each generating project, 35 years for the transmission system, 20 years for conservation investment, and the service life for each replacement. Each year the amount of new power investment expected to be made that year is added to the allowable unamortized investment. That same amount also is subtracted from the allowable unamortized investment when that power investment is due. Thus, the resulting total for each year represents the maximum amount of power investment that can remain unamortized and still comply with the established repayment criteria.

Consequently, the Repayment Study determines whether the repayment criteria are met by comparing the estimated future unamortized power investment with the allowable unamortized investment. If the unamortized investment exceeds the allowable amount for any investment in any year, this indicates that the repayment criteria are not being met and that an increase in revenues will be necessary to assure complete recovery of all power costs within the expected repayment periods.

G. Need for Revenue Increase

In compliance with statutory requirements and Department of Energy policy, BPA prepared a current Repayment Study to test the adequacy of the revenues from the existing rates. The current Repayment Study tested whether the expected revenues from the existing rates would cover all repayment obligations. The study demonstrated that the revenue level needed to satisfy all the repayment obligation is higher than the revenue expected from current rates.

Since the last time power and wheeling rates were adjusted (July 1, 1981), BPA has experienced significant cost increases including the addition of new programs required by the Regional Act. The cost increases include substantial increases in the cost of nuclear power plants from which BPA has acquired power generation capability; and increases in costs to operate, maintain, and construct new Federal generation and transmission facilities. Interest costs also have increased considerably. Corps and Bureau projects now have an incremental interest rate of 9.5 percent, BPA is facing interest rates of about 14.4 percent for funds it borrows from the Treasury, and the interest rate is about 14.25 percent for financing of the nuclear projects from which BPA has acquired capability.

A revenue increase also is needed to enable BPA to repay its deferred annual expenses. Rather than repay the entire deferral in FY 1983, the revenue level is set to collect the deferral over three government fiscal years because of the complications of Sections 7(c) and 7(b)(3) of the Regional Act. These payments are in addition to the regularly scheduled amortization payments that would have been scheduled if no deferral existed. The more liberal three-year period is being used to repay the deferral because of concern for the current poor economic conditions and the adverse affect that a larger rate increase will have on BPA customers. The deferral must be repaid before amortization payments to the Treasury can be credited to amortize the unamortized investment.

H. Results

The current Repayment Study, which was run after the close of the hearing and which determines a revenue level based on the record considered as a whole, indicates the need for an increase of approximately 58 percent in overall revenues. This increase includes all costs associated with BPA's obligations. Under existing rates BPA would collect approximately $1.4 billion in FY 1983. Under the proposed rates revenues are expected to total $2.2 billion. This revenue adjustment will increase BPA's expected revenues by $814.5 million for FY 1983. This increase is sufficient to fully repay over the three-year period FY 1983-85 the total anticipated deferral of $217.9 million plus normal amortization. The rate increase should produce a total transfer to Treasury of $222.7 million in FY 1983 plus pay all current interest expense.

The revenue requirement is based in part on the following estimated payments to the Treasury:

(000)

FY	Amortization	Deferral	Payment to the Treasury
1983	$145,485	$ 77,259	$222,744
1984	115,623	63,697	179,320
1985	117,840	76,956	194,796
Totals	$378,948	$217,912	$596,860

Actual repayments must be applied to deferrals before amortization can be made, so the entire deferral of $217,912,000 will be repaid in FY 1983. In FY's 1984 and 1985 the entire repayments will be applied to amortization.

I. Revenue Requirement Issues

1. Treatment of Conservation Program Bonds

The costs of BPA's conservation programs are to be financed with revenue bonds issued either by BPA or its customers. It currently is estimated that these bonds will carry a 20-year life, and an interest expense of 14.7 percent and 13.9 percent for FY 1982 and FY 1983, respectively (Meyer, BPA, Exh. BPA-66, p. 7-8). These bonds are handled like investments in the Repayment Study with a 5-year call provision and will be considered for repayment using the highest interest rate first criteria which is the same as BPA's treatment of bonds for construction. This differs from the initial Repayment Study which treated the full obligation of the conservation financing on a mortgage basis. The revised method is supported by the Joint Customer Proposal (McCullough, JCP, Exh. JCP-2, p. 2).

2. Inflation Rates

The Repayment Study supporting the initial power rate proposal used an 8.7 percent inflation rate for FY 1982 and a 7.3 percent inflation rate for FY 1983. These rates were based on an analysis of the information available to BPA in February 1982. The inflation rate, as well as the interest rate for bonds issued during the test year (October 1, 1982-September 30, 1983), can have a significant impact on the annual costs and therefore on the wholesale power rates. As a result of the significant variations in the rate of inflation and in interest rates, it is important that the most current information on the record be examined in developing the final rates.

BPA reviewed inflation rates again in April 1982 to determine whether a revision in the assumed inflation rate was appropriate for the revised Repayment Study. I decided that the Gross National Product (GNP) deflator rate for FY 1982 and FY 1983 from the FY 1983 U.S. Budget was the most appropriate rate to use. The GNP deflator rate is representative of several other similar indices examined and discussed in the record. Consequently, I have directed the staff to use inflation rates for FY 1982 and FY 1983 of 8.2 percent and 6.5 percent, respectively (Meyer, BPA, Exh. BPA-66, Attachment 6).

3. Washington Public Power Supply System (Supply System)

In the initial Repayment Study, costs for Supply System Projects 1, 2, and 3 were derived using a mortgage formula to determine annual interest and amortization payments on all bonds issued through the end of the cost evaluation period. Those costs were determined using actual bonds issued through December 1981 and a projected schedule of bond issues from January 1982 through August 1983. The use of a mortgage formula tends to levelize those annual payments and does not necessarily reflect how those payments actually occur (Kallio, BPA, Exh. BPA-64). BPA's witness on Supply System costs introduced, in prefiled testimony, a new method for calculating those costs that more accurately reflects how those costs will occur. To derive cost estimates, the new method uses actual interest payments and bond retirements for all outstanding bonds, and interest and amortization payments on a mortgage basis for projected bond sales.

It was suggested by the Public Power Council that BPA recognize the actual interest payments and bond retirements from the recent Supply System bond issues in our Repayment Study supporting the final rate proposal. We agreed and in rebuttal testimony, BPA's witness stated that BPA had revised its earlier estimates to reflect the February and May 1982 bond issues, a new schedule of bond issues for the remainder of the cost evaluation period, and the construction extension on Project 1 (Kallio, BPA, Exh. BPA-64). The effect of these changes is a $105 million reduction in FY 1983 Supply System costs. I have directed that this data be included in the final Repayment Study.

In his prefiled testimony, the Joint Customer's witness on Supply System costs suggested that BPA reduce its post-1983 Supply System requirements by an amount equal to the investment income earned on the balance remaining in the Supply System's construction fund for each project at the end of the cost evaluation period (Hittle, JCP, Exh. JCP-6). The witness stated that to do otherwise would result in current ratepayers paying higher rates than they should. The Joint Customers assert in their Opening Brief (July 9, 1982) that BPA's witness indicated during rebuttal cross-examination that BPA could not reduce its post-1983 Supply System costs as suggested. Further, if the Supply System were to finance the entire amount necessary to complete Projects 1, 2, and 3 in the test year, BPA would be obligated to pay the associated debt service and that debt service could not be reduced by the investment income derived on the construction fund. BPA contended both in its rebuttal testimony and its July 9, 1982, Memorandum that the Supply System Board of Directors Resolutions are controlling and provide that all interest earned on investment of money in the construction fund accrues to the Construction Fund. Portland General Electric contends in its Reply Brief that BPA did not adequately address the Joint Customers' issue in its Memorandum and suggests that BPA make the reduction proposed by the Joint Customers (PGE Reply Brief, pp. 15-16).

The revenue requirement is based on a cost evaluation period. The costs and obligations facing the FCRPS are to be evaluated given the conditions of that period and the available revenues. Consequently, it would be inappropriate to base the level of amortization and deferral to be repaid in the test year on a financial formula that did not appropriately address only the conditions of the test year. The demonstration that an appropriate amount of amortization is being scheduled in the test period is done by holding the revenue and the costs constant over the repayment period. BPA has some flexibility in choosing the length of the test period. For the 1982 filing, I have decided that the test period should correspond to the 1983 Federal fiscal year. Changes in resource obligations beyond that test period will be reflected in future rate filings.

BPA assumes that construction of Supply System Projects 1, 2, and 3 will be completed. The Repayment Studies supporting both the initial and the final rate proposal are intended to represent conditions that exist during the cost evaluation period. This approach is consistent with Department of Energy (DOE) Order RA 6120.2. These existing conditions include the construction phase of the Supply System at the level defined by the amount of bonds sold by the end of the cost evaluation period. I adopt the interpretation of BPA's witness and counsel regarding the appropriate and lawful use of interest in the construction fund and conclude that the interest earned on the construction fund will accrue only to the construction fund and, therefore, should not be used to retire bonds.

Concerning the hypothetical question regarding financing the entire amount necessary to complete Projects 1, 2, and 3 in the cost evaluation period, BPA is given the authority and responsibility to approve bond resolutions and bond sales in the Project Agreements between BPA and the Supply System providing for construction and operation of Projects 1, 2, and 3. The amount of each financing is based on the Supply System's need for construction funds for a specific period of time and a projected schedule for subsequent bond sales. BPA reviews the cash flow projections, used to establish the amount of construction funds required from a financing, to determine whether those projections are reasonable given recent and planned construction activity. We approve both the Supply System's financing schedule and the amount of each specific financing. I view the hypothetical question posed to BPA's witness as an attempt only to establish consistency in our treatment of Supply System costs, not as a suggestion that we would approve such a financing.

4. Trojan Nuclear Plant

Trojan Nuclear Plant costs included in the Repayment Study supporting the initial rate proposal were overstated by approximately $3 million. BPA's witness on Trojan costs indicated in initial cross-examination that the $3 million working capital fund that Eugene Water and Electric Board maintains was inappropriately included in the original cost estimates (TR. 1181-82). The Joint Customers agreed that this reduction should be made. We have corrected our original estimate of costs associated with the Trojan Nuclear Plant for the final Repayment Study.

5. Operations and Maintenance

Several parties expressed concern about the revised data used in the operations and maintenance category. It is my opinion that a requirement of DOE Order RA 6120.2 is to utilitze the best data available. The hearing process itself, mandated under the Regional Act, allows for the customer groups to have an effective voice in the formulation of the rate setting process. If all data were frozen at the start of the hearing process it would abrogate the purpose of the process. It is my intent that all relevant information developed and presented during the hearings either by BPA or the customer groups, can be incorporated into the Repayment Study and thus the rate level. I also believe that it is not the purpose of the rate setting process to make program determinations, but rather it is to review the costs of programs. I have determined that sufficient information was provided concerning costs of programs included under the operations and maintenance category contained in the Repayment Study. In addition, these costs were compiled using sound business principles reflecting programs that BPA has administratively implemented or approved. I therefore have concluded that the revised data presented by witness Meyer is appropriate for use in this rate proceedings.

6. Electric Power Research Institue (EPRI) Contributions

Concerns were expressed by various parties about BPA contributions to EPRI (See Brawley, PPC, Exh. PB-19). After reviewing their concerns and the EPRI benefits to the Northwest, I conclude that it is appropriate that contributions continue. BPA contributes to EPRI, participates on the EPRI Board of Directors, and protects regional interest by our involvement in EPRI's advisory structure. EPRI is the only organization of its kind that can coordinate the efforts of utilities to engage in research on common utility problems that would be too extensive to be undertaken by any single utility. BPA and PNW utilities achieve greater benefit per dollar invested in EPRI than if either the PNW utilities or BPA carried out the same research independently. BPA carries on its own research and development program efforts for good and practical reasons in accordance with sound business practices.

Because of the current economic situation, as well as exercising some control over the growing cost of EPRI, the FY 1983 contribution will not exceed the FY 1982 contribution. This is not in compliance with the stated wishes of EPRI, but is prudent in controlling costs incurred by BPA. To this end, I have held the contributions to $7.7 million dollars, which is the FY 1982 level.

7. Methodology

Major concerns were raised by various parties concerning the methodology of the Repayment Study. These concerns deal with: (a) the treatment of deferral; (b) the inclusion of a cash flow adjustment; (c) the recognition of a five-year call provision on revenue bonds; (d) the adoption of a linear program to determine the revenue requirement; and (e) the treatment of the resource costs after the cost evaluation year.

a. Deferral

The Joint Customer Proposal suggested that the deferral be paid over a longer period of time than that suggested in the initial Repayment Study. They also presented an alternative study that handled the repayment of the deferral in much the same manner as the initial study (McCullough, JCP, Exh. JCP-7 & 8). It is my opinion that BPA must be a responsible member of the Federal community as well as of the region and therefore must pay its debts in a timely fashion. I also feel that BPA's credit worthiness with the financial markets and the Federal government is suffering because of its outstanding deferred annual expenses. Furthermore, BPA's increased responsibilities for acquisition of resources, including conservation, require that it maintain a sound fiscal condition. Not only must the current deferrals be eliminated but we also must make future planned amortization payments on schedule. However, in recognition of the economic condition of the region, I have determined that this burden will be built into the rates over a 3-year period and that during this 3-year period the payment of amortization will not be delayed. To that end, a revenue level has been developed that will assure BPA's ability to repay the deferral and that portion of the Federal investment that the FCRPS otherwise would be able to pay through 1985 if there had been no deferral outstanding at the end of FY 1982.

b. Cash Adjustment

It is my understanding that the Joint Customers agree that BPA should include a cash lag adjustment (McCullough, JCP, Exh. JCP-7, p. 4). It is my opinion that the DOE Order RA 6120.2 requirement, that rates be consistent with sound business principles, requires that the Repayment Study incorporate the added cash requirement needed to serve the change in revenue requirement. The accrual basis does not recognize cash position and as such does not fully address the repayment obligation during the cost evaluation period. The repayment obligation can be satisfied only by cash transfers. The additional revenue requirement needed to fulfill the cash obligation is appropriate if the repayment obligation is to be fully recognized for the cost evaluation period. Therefore, we are including an additional revenue requirement of $30 million for cash flow needs as detailed in the Documentation for the Repayment Study.

c. Call Provision

BPA's Treasury bonds have a clearly stated five-year call option that is an obligation that must be recognized. The inclusion of this obligation is mandated by all existing statutory and regulatory authorities addressing the recovery of costs of the FCRPS. Therefore, this provision is included in this Repayment Study. The Joint Customers support an increase in BPA's revenue requirements to cover the inclusion of the five-year call provision for BPA's bonds (McCullough, JCP, Exh. JCP-7, p. 4).

d. Linear Programming Method

I have reviewed the results of the Repayment Study and find that they are accurate for the purposes of developing rates. BPA has a statutory obligation to insure that rates are as low as possible consistent with sound business principles. The computer program that generates the Repayment Study has been reviewed extensively by BPA, and by representatives of the parties. It is my understanding that these reviews did not find significant fault with this computer program. As indicated by the Joint Customers, BPA's present model is very sophisticated and produces accurate results (McCullough, JCP, Exh. JCP-7, p. 16). In terms of overall complexity, I agree with the Joint Customers that BPA's repayment model is very complex and as such may be difficult to understand. I intend that BPA will continue to work towards simplifying its repayment process, where appropriate, and make it more understandable, but that accuracy will not be sacrificed for the purpose of simplification.

I find that the linear program proposed by the JCP in Exh. JCP-8 is incomplete and inadequately documented (TR. 3833-34, 3837). At this time, I cannot consider changing our model for a linear programming model because a thoroughly tested and documented linear programming model does not now exist for this purpose. Therefore, the existing repayment model will continue to be used. However, the BPA staff will continue to review and evaluate linear programming as an alternative approach to modeling repayment requirements.

e. Resource Costs Beyond Test Year

Some parties indicated that it would be appropriate to eliminate the cost of power purchases beyond the cost evaluation year in the Repayment Study.

The revenue requirement is based on a cost evaluation period that is based on an average water year. The costs and obligations facing the FCRPS are to be evaluated given the conditions of that period and the available revenues. Consequently, it would be inappropriate to base the level of amortization and deferral to be repaid in the test year on a financial formula that did not appropriately address only the conditions of the test year. This financial formula leading to BPA's ability to repay a specific amount to the Treasury is a result of the resources available for sale and the cost of those resources. The demonstration that an appropriate amount of amortization is being scheduled in the test period is done by holding the revenue and the related costs constant over the repayment period.

BPA has some flexibility in choosing the length of the test period. For the 1982 filing, I have decided that the test period should correspond to the 1983 Federal fiscal year. Changes in resource obligations beyond that test period will be reflected in future rate filings.

V. 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 load growth because of increased customer demand or to be avoided if customers do not demand additional increments. 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 is a method of applying the principles of marginal cost pricing to electric rates, given the constraints under which utilities must operate. The process involves an analysis of expected additional demands on BPA's system and planned additions of generation and transmission facilities to meet these demands. The planning schedule for additions to generation and transmission capacity provides a basis for defining the investments and expenses to be included in the TDLRIC Analysis. The planning horizon should allow 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 Cost of Service Analysis and in the development of illustrative TDLRIC rates. Application of the rates would provide information to consumers which would enable them to make informed consumption decisions based on the costs to society of providing electric power.

B. Theoretical Considerations

The theoretical basis for the TDLRIC Analysis is derived from a branch of economic thought known as "welfare economics". A major tenant of welfare economics is that under optimal conditions the price of a good should equal the marginal cost of producing that good. Prices which are set at greater or less than marginal cost will lead to consumption decisions that do not reflect the foregone societal opportunities involved in the production of that good. The purpose of a price based on marginal cost is to convey to consumers and producers correct price signals reflecting the costs to society of producing goods and services. The ultimate goal of this pricing is the efficient allocation of resources.

A number of comments were made by the parties concerning the appropriateness of BPA's application of marginal cost principles to rates. In particular, it was pointed out that maximum social efficiency cannot be attained through marginal cost pricing since the theoretical conditions on which this pricing is based do not exist (Shanker, APAC, Exh. PA-1, p. 4). In addition, parties claimed that movement toward rates based on marginal cost principles may result in movement away from optimal conditions, thereby making matters worse (Shanker, APAC, Exh. PA-1, p. 36).

The TDLRIC Analysis is a specification of those costs which are incurred if additional service is provided or those costs which can be avoided if service is diminished. It is not an attempt to reach maximum social efficiency per se, but rather an attempt to adjust rates to reflect forward looking costs and relative cost relationships. While illustrative incremental cost based rates are provided for informational purposes, BPA is not attempting to implement marginal cost pricing. I believe that the question of whether or not the development of marginal cost based rates may be a movement away from the optimum has not been answered in a satisfactory manner and should not be allowed to prevent the development of more effective price signals.

An additional comment indicated that the use of the long run incremental cost of energy as a measure of marginal energy cost is incorrect and that the TDLRIC Analysis should be based on short run considerations (Shanker, APAC, Exh. PA-1, p. 31). BPA has considered the use of short run measures of incremental cost. Short run costs are less stable than long run costs and would not improve BPA's ability to promote rate stability. The unstable nature of short run measures also affects long term plans that depend upon incremental cost analyses. APAC and PPG also commented on the apparent inconsistencies of BPA's TDLRIC Analysis with the National Economic Research Associates' (NERA) long run incremental cost (LRIC) methodology (Shanker, APAC, Exh. PA-1, p. 2; Garman, Opatrny, Knitter and Sunday, PGP, Exh. PB-20, p. 27). While the TDLRIC Analysis is based on the NERA approach to marginal costing, I believe that it is modified properly in recognition of how incremental costs are incurred on the BPA system. The ICP and OPUC agree with this position (Shue, ICP, Exh. IO-17, p. 2; White, OPUC, Exh. SC-6, p. 3).

C. Long Run Incremental Cost of Generation

1. Capacity Costs

The LRIC of generation consists of both a capacity and energy component. The LRIC of capacity is based on resources that would be added to the system to meet additional peaking requirements. In the past, BPA relied on hydro peaking units constructed by the Army Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau) as the source of additional long term peaking capacity. BPA's short term purchase authority could not be used to fulfill long term obligations. However, with BPA's new acquisition authority under the Regional Act, the limited sites for additional hydro peakers, and the small number of additional hydro peakers currently planned or under construction, BPA's long run source of additional peaking capacity most likely would be combustion turbines. Consequently, a generic single cycle combustion turbine is the incremental resource used as a basis to determine incremental capacity costs. Combustion turbines are generally recognized as the least cost resource for determining the LRIC of capacity.

To produce BPA's LRIC of capacity, annualized investment costs, annual operation and maintenance, and annual fuel costs (all expressed in mid-FY 1983 dollars) are credited for the value of the incremental energy produced and divided by the nameplate capacity adjusted for a reserve factor. The LRIC of capacity for BPA is \$51.60 per kilowatt (Table 2, TDLRIC Analysis).

APAC observed that BPA lacked an analytical basis for choosing combustion turbines as representative of incremental capacity costs (Shanker, APAC, Exh. PA-1, p. 27). I disagree with this observation. Analysis by BPA indicates that a combustion turbine is the most probable, least cost resource for determining the LRIC of capacity. This selection of the combustion turbine was supported by the ICP and PPC (Shue, ICP, Exh. IO-17, p. 6; Russell, PPC, Exh. PB-7, p. 9).

A number of comments were received concerning the use in the initial TDLRIC Analysis of a 7.5 percent capacity factor for the combustion turbine. BPA staff's choice of a capacity factor was based on the DOE/FERC Hydroelectric Power Evaluation which stated that "a 7.5 percent capacity factor appears to be an appropriate estimate for a typical, large combustion turbine plant operation." As noted by IPUC and the ICP; further examination of the cited document also indicates that for a unit of the 100 megawatt size used in the TDLRIC Analysis, a 3.3 percent capacity factor may be appropriate (Drummond, IPUC, Exh. SC-4, p. 5-6; Shue, ICP, IO-17, p. 5-6). However, as was made clear by OPUC and the ICP, various factors unique to a particular utility affect the selection of the appropriate capacity factor for a combustion turbine peaking unit (TR. 3116, TR. 3787). It is probable that for BPA's predominately hydro system, combustion turbines would be block loaded to some extent and hydro peaking facilities would be used for periods of extreme peaks subject to certain sustained peaking constraints. With respect to both the potential for block loading and the evidence cited in the DOE/FERC document, I find that a 5 percent capacity factor would appropriately balance these considerations.

It also was remarked that the capacity reserve factor for combustion turbines should be based on the specific outage rate for the peaking unit rather than on a composite rate based on peaking and baseload units. BPA staff applied a melded capacity reserve factor to the LRIC of capacity to reflect a weighted forced outage rate for those BPA units expected to come on-line in the region which would provide capacity. Since the LRIC of capacity applies to both a peaking and baseload unit, I believe that it is appropriate to reflect the forced outage rates of each type of facility in the reserve factor.

An additional comment suggested that in computing the LRIC of capacity, the capacity reserve factor should be applied only to the fixed cost of the combustion turbine (Shue, ICP, IO-17, p. 4-5; TR. 3730-1 and TR. 3746-8). While it is true that some variable costs are included in the LRIC of capacity, the total cost after allowance for the energy credit nonetheless is considered as capacity cost in the long run and should be adjusted by the capacity reserve factor.

Parties were critical of BPA's choice and treatment of fuel costs for the generic combustion turbine. In particular, it was argued that BPA did not choose the least costly fuel option and that BPA should have used the Data Resources Incorporated (DRI) price for distillate fuel in determining the LRIC of capacity (Garman, Opatrny, Knitter and Sunday, PGP, Exh. PB-20, p. 32; Shue, ICP, Exh. IO-17, p. 3-4; TR. 3737-8, TR. 3743-5, TR. 3748, TR. 3781-5, and TR. 3798-3800). I agree that the least-cost fuel option should be chosen with provisions for a backup fuel where there is the potential for supply interruptions. Consequently, for the final proposal, a composite, levelized fuel cost has been determined which reflects the use of diesel No. 2 oil as a backup fuel for the least cost option which is natural gas. The DRI price of distillate fuel is not proper for use in the development of fuel costs for a combustion turbine because the DRI index is a national composite of all types of distillate fuels. A more accurate approach is to calculate fuel costs based on specific quotes for the type of fuel used in combustion turbines within the region (No. 2 diesel).

It also was argued that the LRIC of capacity should be doubled to reflect the recovery of costs of the peaking unit during the six months in the year that the combustion turbine would be operated (Hittle, NW Irrigation, Exh. PB-23, p. 39; Exh. PB-30, p. 30). This argument ignores the fact that the annual cost of capacity is recovered over both the secondary peak and peak periods as shown in Table 12 of the TDLRIC Analysis. This combination of peak and secondary peak encompasses the 12 months of the year which is the period of time over which the peaking unit costs would be recovered.

An additional comment suggested that the running costs of the combustion turbine should be excluded from the LRIC of capacity calculation (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 28). BPA's approach recognizes that to provide capacity to the system the combustion turbine peaking unit must be operated. However, after some period of operation the unit begins to generate incremental energy. The energy credit procedure offsets the cost of any incremental energy produced by the peaking unit. Thus, BPA's methodology properly assigns all of the remaining combustion turbine costs to capacity.

2. Energy Costs

Firm energy development for the near term will consist of conservation, renewable resources, cogeneration facilities, and coal and nuclear thermal plants. There are few suitable sites remaining for further hydroelectric development to produce energy. Therefore, thermal plants are the most suitable long run alternative for serving future baseload. Thus, thermal plants are planned for the Region's future baseload energy needs. Other than short term purchases, Federal thermal power supplies currently are derived from power purchases under net-billing agreements. The long run incremental cost of producing energy is based on the cost of baseload thermal power with an adjustment for a capacity credit. For the LRIC of energy analysis, BPA assumed the technologies associated with Washington Public Power Supply System (Supply System) nuclear plants Nos. 1, 2, and 3 as typical of baseload power plant costs. Based on these plants, the weighted average LRIC of energy is 40.81 mills per kilowatthour (Table 3, TDLRIC Analysis).

There were a number of objections to BPA's use of the Supply System plants' cost streams in determining of the LRIC of energy. These comments stated that BPA should have based its cost determination on: (a) a generic coal unit (Carter, DSI, Exh. DS-4, p. 6; Exh. DS-8, p. 1-3), (b) Colstrip plants 3 and 4 (Garman, Opatrny, Knitter, Sunday, PGP, Exh. PB-20, p. 32-3), or (c) Supply System plant 2 (Saleba, Russell, Schneider, Hutchison, WPUD, Exh. PB-16, p. 19-20). I do not agree that the use of a generic coal unit or the Colstrip plants 3 and 4 cost streams would provide an appropriate analysis of the least cost means of meeting the need for energy in the long run. As shown in Appendix D of the TDLRIC Analysis, a generic coal plant at the load center is more expensive than a nuclear plant on a levelized life cycle cost basis and would not be selected as the least cost resource. Levelized life cycle costs are a more important consideration to the prudent utility planner than first year costs (Shue, PPL, Exh. IO-29, p. 2). The use of Colstrip plants 3 and 4 which are units at the mine location would not provide a meaningful basis for the LRIC of energy unless adjustments were made to reflect the trade-off between transmission versus coal transportation costs associated with a mine-mouth versus a load center facility. Currently, there is no evidence that the adjusted cost of a mine-mouth coal plant is cheaper on a life cycle cost basis than the load center plant. As a result, I conclude that a generic nuclear plant is the least cost resource compared to either a generic load center or mine-mouth coal plant.

I also disagree with the suggestion that Supply System plant 2 should be used to determine the LRIC of energy. BPA used as the basis for the LRIC of energy the costs of Supply System plants 1, 2, and 3, adjusted to FY 1983 constant dollars and averaged over the three units. BPA believes this method gives the costs for a representative thermal baseload plant. The representative plant is an "average" of the technologies contained in Supply System plants 1, 2, and 3. It would not be appropriate to select one plant and assume that it represents the costs of a generic plant that would be available to BPA in the future.

An additional comment suggested that fixed costs should be excluded from the calculation of the LRIC of energy (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 28). While this suggestion may be accurate in the short run, in the long run when all costs are variable, fixed costs are properly included in the LRIC of energy.

D. Economic Carrying Charge Formulation

The annual carrying charge is the rate applied to the total investment cost to calculate the annual cost of the investment. The carrying charge applied annually over the average service life to the cost of an asset of known present value will fully recover the initial cost of the asset and the cost over time of the funds used to purchase it.

Conceptually, in contrast to a nominal carrying charge, an economic carrying charge represents a "fair rental rate" which may change over the life of a project. Since inflation causes the costs of competing projects to rise, the pattern of rental payments should rise at the projected inflation of the project's price. That is, the charge is "real" in the sense that it creates a stream of payments that are constant over time in real terms. Table 1 of the TDLRIC Analysis presents the annual carrying charges used in the TDLRIC Analysis and Appendix A presents the formula used for determining the constant real charges. The results of the initial TDLRIC Analysis were revised for the final TDLRIC Analysis to reflect the most recent Data Resources, Inc. (DRI) inflation and interest rate projections.

Comments were critical of the economic carrying charge used in the TDLRIC Analysis suggesting that it does not reflect the demands made on ratepayers to amortize the costs of incremental capital investments. The DSI's suggested that a more suitable approach would be to use a nominal carrying charge that resulted in a stream of payments that are level in nominal terms (Carter, DSI, Exh. DSI-4, p. 16). I believe that the suggested approach is incorrect for an LRIC analysis. As noted by OPUC, the use of a nominal carrying charge would value an asset higher in real terms at the beginning of its life and lower at the end of its life (White, OPUC, Exh. SC-6, p. 10-11). This may lead to a situation where customers in one time period would subsidize those who receive the same benefits in subsequent time periods. In contrast, an economic carrying charge correctly develops a stream of plant related costs that is level in real terms. In addition, an economic carrying charge properly measures the change in total capital costs of bringing a long-lived asset on line in the test year as opposed to a future year at inflated prices. PP&L commented that an analysis that incorporates a nominal carrying charge would not reflect the additional inflation related costs incurred as a result of a delay in an investment decision (Shue, PPL, Exh. IO-29, p. 7).

Additional comments suggested that BPA's assumption of a zero rate of technological progress in the carrying charge calculation is inappropriate (Carter, DSI, Exh. DS-4, p. 18; Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 30). While I do recognize that making an acquisition of a facility in the future instead of in the test year may lead to the purchase of a more efficient asset because of technological improvements, I do not feel that there is enough evidence at present to make this adjustment. It also should be recognized that future increases in plant costs for health and safety regulations and pollution controls may well offset the benefits from technological improvements in generation efficiency (Shue, PPL, Exh. IO-29, p. 8-9).

It also was argued that the economic carrying charge employed in the TDLRIC Analysis was incorrect because it ignored the shortened asset life used for project evaluation in the competitive market. That is, the recovery of capital should reflect the span of time over which the competitive market writes off the cost of an asset (Carter, DSI, Exh. DS-8, p. 5). One suggested measure of this time period is the lower limit of the asset depreciation accelerated tax life allowed by the Internal Revenue Service (IRS). In the initial TDLRIC Analysis, BPA staff calculated an economic carrying charge over the average service life of the assets involved. I believe that because the average life is an accurate reflection of the period of time over which the asset may be expected to last, it is the proper time-span over which to recover the initial cost of the asset and the cost over time of the funds used to purchase it.

E. Transmission

The LRIC of transmission is based on additions to transmission investment through 1990 plus annual operation and maintenance expenses associated with new transmission facilities. The analysis of incremental transmission costs includes only the costs segmented to network and generation-integration. Network consists of the facilities that supply bulk power to the delivery, intertie, and fringe segments, including the facilities that serve the transmission function, regardless of transmission voltage. These facilities integrate major system resources directly, or in conjunction with BPA's generation-integration facilities or interconnections with other utilities. Generation-integration costs represent additional transmission investments required to establish a connection from the high voltage side of step-up transformers at new generation facilities through switch connectors to the transmission grid. Generation-integration costs are associated with facilities connecting Federal generation projects to the BPA transmission system. Generation-integration plant costs are classified to capacity and energy in the same manner as the corresponding generating projects, while network costs represent capacity costs only.

The long run incremental annual cost per kilowatt of BPA's transmission network system is $26.77 (Table 7, TDLRIC Analysis). Generation-integration transmission annual costs per kilowatt include both a capacity and an energy component. The generation-integration incremental annual capacity cost per kilowatt is $0.05 (Table 8, TDLRIC Analysis). The annual generation-integration incremental energy costs are 0.01 mills per kilowatthour (Table 8, TDLRIC Analysis).

F. Selection of Costing/Pricing Periods

The variation of cost by time periods is an important consideration in an analysis of incremental costs. In the long run, because of the variable nature of consumption over peak hours or seasons, additional generation and transmission capacity may be required. However, increases in offpeak consumption normally do not necessitate capacity additions. As a consequence, capacity costs are normally incurred to meet peak period loads rather than offpeak loads.

If pricing failed to recognize differences in the costs incurred by time period, it could promote the inefficient use of resources. If costs were not differentiated by time period, the rate charged during peak periods would be less than the cost of producing the service. Such a charge would give the consumers the wrong price signal and could cause them to demand more than they would have demanded had the price reflected the incremental cost. The deficit that would result from charging less than incremental costs would be recovered from offpeak sales for which the rate would be greater than the incremental costs.

Theoretically, pricing should vary instantaneously with cost changes. Obviously, such a pricing scheme would be difficult or impossible to determine and administer. Thus, the concept has been simplified by grouping intervals of time that are as homogeneous as possible with respect to unit production cost. This has led to time-of-use rates that change according to the season of the year, the day of the week, and the time of the day.

The following criteria are used for selecting costing/pricing periods:

1. Hours or months with similar costs should be combined into like groups,

2. The number of periods selected should be feasible to administer, and

3. The periods chosen should be broad enough to allow for shifts in loads without shifting the peaks outside the peak period (Initial TDLRIC, Exh. BPA-6, p. 20).

From an analysis of BPA's firm load for FY 1979-1981 (Table 10, TDLRIC Analysis), Federal Columbia River Power System (FCRPS) generation data, West Group Region probabilities of negative margin (PONM) (Table 9, TDLRIC Analysis), and ambient temperatures at time of transmission peaks (Charts 1, 2, and 3, TDLRIC Analysis), it was determined that the peak period for generation capacity should be defined as December through May, Monday through Saturday, 7 a.m. to 10 p.m. (Table 11, TDLRIC Analysis). A secondary peak season for generation capacity costs should be June through November, Monday through Saturday, 7 a.m. to 10 p.m. The combination of these two periods (all months, Monday through Saturday, 7 a.m. to 10 p.m.) forms the peak period for incremental transmission costs. The offpeak capacity hours for incremental costs should be all other hours of the year.

The specification of costing/pricing time periods does not apply to the energy component of BPA's incremental costs. The LRIC of generation energy does not vary by time period. Baseload thermal plants operate throughout the year except for planned maintenance, refueling, and forced outages. Under the planning criteria of critical water, an increase in demand for energy during any hour of the year requires additional baseload thermal capacity. Since the costs of providing energy from baseload thermal plants are the same for BPA each hour of the year, the LRIC of energy is neither diurnally nor seasonally time differentiated. In addition, transmission generation-integration energy costs are not time differentiated because they are directly related to the generation facilities being integrated.

It was recommended that the incremental energy costs of thermal generation should be assigned to the periods when the thermal plants are expected to be operated during average water conditions rather than during critical water conditions as is done in the TDLRIC Analysis (Hittle, NW Irrigation, Exh. PB-30, p.28). I disagree with this recommendation. Baseload thermal plants are designed to be operated throughout the year except for various types of outages which may occur throughout the year. These baseload thermal resources have been added to the FCRPS to supply needed incremental energy on an annual basis under critical water conditions, which is BPA's planning criteria. From a planning perspective, this need for incremental energy may occur at any hour of the year and will require baseload thermal additions. Thus, the LRIC of generation energy does not vary by time period.

A number of criticisms were made concerning BPA's probability of negative margin (PONM) analysis which is the basis for the assignment of the incremental costs of capacity to each hour. Among these comments were: (1) the PONM analysis should have been conducted prior to subtracting scheduled maintenance, (2) the PONM analysis does not adequately define the seasonal capacity periods, and (3) nonfirm loads should be excluded from the PONM analysis (Hittle, NW Irrigation, Exh. PB-30, p. 2, 7-9).

I do not believe that the PONM analysis should be conducted prior to removing the costs of maintenance since this would imply that the resource was available when in reality it is not. In addition, the argument has been made that a strict application of the PONM methodology may lead to a situation where a number of non-contiguous months are grouped together as the peak period. While this may be correct, the final analysis should be tempered by considerations such as ease of customer understanding and the possibility of peak shifting. These considerations have led me to conclude that the seasonal capacity periods are adequately supported in the TDLRIC Analysis. Finally, the only nonfirm load included in BPA's PONM analysis is the top quartile or nonfirm portion of the DSI load. When nonfirm loads are constant each month, as is assumed in the TDLRIC Analysis, the peak pricing period analysis is not altered since the relative PONM's do not change.

An additional criticism was that BPA's choice of Saturday as a peak day was incorrect and had little basis (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 37-38). I disagree with this assessment. Generation historical load data indicates that although the Saturday peak is more closely associated with the Sunday peak than the weekly peak, it is significantly greater than the Sunday peak and tends to be more erratic than any other daily peak. Furthermore, an analysis attempting to quantify the potential for generating utilities to shift load to Federal generation suggests that, if Saturday was made an offpeak day, utilities may use their flexibility through various contracts to shift load on Federal resources from Sunday to Saturday. In this event, Saturday peak hours would become even more similar to weekday peak hours and Sunday would become even less similar to the other days of the week. Utilizing the above facts and recognizing the potential for load shifting from customers operating automatic generation control equipment, Saturday is included in the peak period.

Finally, it has been noted that BPA's determination that transmission network costs should not be seasonally differentiated is unsubstantiated. This criticism is based on a recommendation that average annual temperature from 1979-1981, three warmer than average years, be matched against loads from normal temperature years. It is my belief that the proposed approach to seasonally differentiating transmission costs understates the ambient temperature adjustment during cold months. In contrast, BPA's methodology properly adjusts monthly peak transmission load for the ambient temperature at the peak hour. As a result, BPA's analysis shows that transmission network costs should not be seasonally differentiated.

G. Long Run Incremental Cost of Energy Based on a Generic Coal Unit

In the TDLRIC Analysis, a generic coal plant was considered as an alternative incremental baseload unit (Appendix D). It was not shown to be the least cost means of producing energy in the long run on a levelized life cycle basis and was therefore not adopted as the source of incremental energy. This finding is consistent with the admission of the witness advocating use of the generic coal plant (Carter, DSI, Exh. DS-4, p. 8-9). The total levelized life cycle cost of a coal plant is 58.83 mills per kilowatthour. This compares with a levelized life cycle cost, exclusive of the capacity credit, of 49.28 mills per kilowatthour for the generic nuclear plant shown in Table 3 of the TDLRIC Analysis.

A number of comments concerned BPA's comparison of a generic coal plant with the nuclear plant. It was noted by the DSI's that: (1) BPA's assumed nuclear fuel cost real escalation rate of zero was improper; (2) BPA should have used a 75 percent plant factor for the generic coal plant when comparing it with a nuclear plant; and (3) BPA incorrectly calculated the mills per kilowatthour cost of operation and maintenance expense and fuel (Carter, DSI, Exh. DS-4, p. 6-8).

The forecasts BPA staff used for marginal delivered coal price and nuclear fuel price escalation from the test year to the end of the average service life of the unit were taken from the latest DRI projections for these cost items. These projections indicate that nuclear fuel prices will change at the rate of increase of the implicit price deflator resulting in no real price escalation. In contrast, the price of marginal delivered coal is forecasted to increase from 3 to 7 percent above the implicit price deflator over the life of the asset. The assumption of zero price escalation for nuclear fuel was corroborated by PP&L (Shue, PPL, IO-29, p. 61). I believe that the DSI's recommendation that BPA use the projections stated in the draft Electric Power Research Institute (EPRI) Technical Assessment Guide dated February 23, 1982, is inappropriate. The EPRI document cited by the DSI's was an unpublished source which was subject to revision. It is not a source which is consistent with the other DRI projections used by BPA in the TDLRIC Analysis. Finally, the DRI projections are preferable since they are more recent than those contained in the EPRI document.

I do agree with the DSI's recommendation that a 75 percent plant factor should be used for the generic coal plant analysis. This approach is consistent with the recommendation contained in the Pacific Northwest Utilities Conference Committee's (PNUCC) System Planning Office's memo contained in the TDLRIC Analysis documentation. In addition, I agree that BPA incorrectly calculated the mills per kilowatthour cost of operation and maintenance expense and fuel. Both of these changes are reflected in the final proposal.

H. Rates

The results of the TDLRIC Analysis were used to develop rates for FY 1983. The objective was to develop an illustrative rate schedule that would provide BPA's customers with price signals by reflecting the cost of producing additional kilowatts and kilowatthours, irrespective of BPA's revenue requirement.

The first step is the quantification of the total seasonal long run incremental capacity costs (Table 11, TDLRIC Analysis). Each season's total capacity costs are the product of the annual coincidental peak and the appropriate seasonal unit incremental cost. The long run incremental annual cost of generation capacity is $53.41 per kilowatt (Table 2 and 4, TDLRIC Analysis) and generation-integration transmission capacity is $0.05 per kilowatt (Table 8). The peak and secondary peak incremental generation capacity costs are the annual costs apportioned according to the 0.754 and

0.246 factors, respectively, determined by the assignment of costs analysis in Section VI of the TDLRIC Analysis. The monthly demand charges for each of the seasons are equal to the relevant total long run incremental annual capacity costs divided by the sum of the noncoincidental peak demands (Column E and D, Table 12, TDLRIC Analysis). For the secondary peak and the peak periods, this charge is \$2.26 and \$6.43 per kilowatt, respectively. The monthly demand charge for generation-integration during the peak period is \$0.010 per kilowatt and \$0.003 per kilowatt during the secondary peak period. Transmission network capacity costs, not seasonally differentiated, equal \$1.91 per kilowattmonth (Table 13, TDLRIC Analysis).

The cost of energy is neither diurnally nor seasonally time-differentiated. Consequently, the energy charge for generation is 42.31 mills per kilowatthour (Table 3 and 4, TDLRIC Analysis) and the energy charge for transmission generation-integration is 0.01 mills per kilowatthour (Table 8, TDLRIC Analysis) throughout the year.

VI. Cost of Service Analysis

A. Introduction

The purpose of the Cost of Service Analysis (COSA) is to assign responsibility to the various customer classes for embedded costs incurred by BPA in providing service to those customers. The COSA also provides a basis for evaluating the adequacy of current wholesale power rates in the recovery of test year costs. The COSA enables BPA to comply with provisions of Section 7 of the Regional Act relating to the recovery of resource pool costs in the order those resource pools are used to serve BPA's customers.

Chronologically, the Repayment Study and the TDLRIC Analysis logically precede the COSA in the rate development process. BPA's revenue requirement is based on a Repayment Study. The costs assigned to the customer classes by the COSA comprise the total revenue requirement as determined by the Repayment Study. The COSA assigns resource pool costs to the customer classes on the basis of service provided from each of those resource pools. Subsequently, the costs of these pools are allocated to loads served by the pools. Moreover, because a long run incremental cost causation approach to thermal classification is used, and because the time differentiated costs of capacity are inputs to the COSA, it is necessary to complete the TDLRIC Analysis prior to completing the classification and seasonal differentiation portions of the COSA.

The analysis performed in the COSA consists of five basic steps. First, the investment base and annual costs are functionalized into categories of costs related to the functions performed by the power system. Costs are grouped into categories related to generation, transmission, and metering and billing functions. BPA operation and maintenance costs, and BPA's General Plant costs are functionalized based on the Direction of Effort Study. Residential IOU exchange costs are functionalized after an examination of Average System Cost information submitted by exchanging utilities.

Second, classification subdivides the functionalized investment base and annual costs into cost categories related to the components of power: energy or capacity.

Third, costs are seasonally differentiated. Because electricity consumption patterns differ by season, costs can be specifically differentiated as they relate to providing service during the seasons.

Fourth, the Federal Columbia River Transmission System is segmented into seven segments in order to assure an equitable allocation of transmission costs among all classes of service. Not all customer classes use the entire transmission system; thus, segmentation of the transmission system allows a more refined identification of users of each portion of the transmission system. The segmentation process initially identifies transmission facilities in each segment through one-line diagrams. Investment base and annual costs related to each segment are then separated and allocated only to deemed users.

The fifth and final step in the COSA is the allocation of the functionalized, classified, segmented and seasonally differentiated costs. BPA allocates four specific types of costs to customer classes. These are seasonal costs of energy, seasonal costs of capacity, segmented transmission costs, and metering and billing costs. Each type of cost is allocated to customers on the basis of their measured or designated use of the service for which the costs are incurred.

B. Allocation of Deferral

BPA has functionalized and classified the deferral of prior years' interest expense on the basis of the functionalization and classification of all other costs in the COSA. The deferral was allocated to all of BPA's customers on the basis of loads. This treatment of the deferral in the initial proposal was selected because no accurate identification could be made of the specific customer groups causing the deferral.

The ICP claims that a portion of BPA's deferral is directly attributable to the DSI's (Lauckhart, ICP, Exh. IO-15, p.2). They rely on Section 7(b)(3) of the Regional Act which requires that rates charged to preference customers shall not include any costs or benefits of a net revenue surplus or deficiency due to incorrect DSI load projections. The ICP has quantified a portion of the deferral which they claim should be allocated directly to the DSI's. Their analysis computes the monthly difference between FY 1982 projected and actual DSI loads. The difference is calculated as a percentage of projected monthly loads and multiplied by the monthly exchange costs. The ICP claims that the total ($92.54 million) is the portion of the deferral directly attributable to the DSI's (Lauckhart, ICP, Exh. IO-15, p. 4). Other parties also have suggested that BPA attempt to allocate its 1982 deferral amount on the basis of an identification of specific causes of the deferral (TR 4722).

In my view, the deferral has been caused by numerous factors that relate to BPA's ability to precisely project all loads and all costs (TR 4912 et seq). When actual loads are lower than forecast loads and when actual costs are higher than forecast costs used in the development of the rates, it is possible to underrecover costs to the extent that mitigating measures cannot be taken or cannot be effectively implemented. Inaccuracies in all forecasted costs and loads, not just the loads of the DSI's and the costs of the exchange, have contributed to BPA's deferral. For example, during 1982 there have been public agency load underruns, and no new resources loads have materialized. These underruns have resulted in some resource costs being avoided; however, some transmission and overhead costs were unrecovered. Offsetting these underrecoveries were nonfirm sales greater than forecast resulting in higher than forecast nonfirm revenues. Costs also have varied from those forecast in developing the current rates. The most notable difference between projected and actual costs were those of Supply System plants 1, 2 and 3 (Kallio, BPA, Exh. BPA-20). Other actual cost components have differed greatly from those forecast in developing the 1982 rates.

I believe that it is an extraordinarily complex task to retroactively trace differences between forecast and actual costs incurred in any prior year, and to attribute such differences to any customer group. In my view, no party to this rate filing has proposed a method by which BPA could equitably allocate the deferral on a cost causation basis.

The ICP position with respect to allocation of the deferral assumes that a specified amount of the deferral is directly related to underrecovery of exchange costs. I do not believe that it is reasonable at this time to assign a specific portion of the deferral directly to the cost overruns or load underruns associated with a particular customer group. In addition, I believe that the determination required by Section 7(b)(3) concerning the amount to be collected or repaid by the DSI's will not be determinable until after July 1, 1985. I am committed to unraveling the requirements of Section 7(b)(3) of the Regional Act in order to develop a methodology that can effectively address those requirements. BPA is currently participating in formal discussions with its customers in order to develop a common perception of the requirements of Section 7(b)(3) of the Regional Act.

C. Functionalization

The ICP expressed concern that BPA's Direction of Effort Study (DES) does not appropriately functionalize BPA operation and maintenance costs between generation and transmission. One concern related to an instruction to BPA managers providing input to the DES. The instruction stated that "if an activity does not clearly fall into the generation or metering and billing function, it should be treated as transmission," (Exh. BPA-28, Attachment 1). The ICP argues that this instruction creates several unlikely allocations, particularly with respect to activities of the Audit staff and General Counsel's office, most of the costs of which have been functionalized to transmission. One suggestion offered by the ICP is that costs not clearly identified by function, be functionized as metering and billing costs. (McCullough, ICP, Exh. IO-18, p. 6). I disagree with this suggestion because adopting it would distort BPA's metering and billing cost quantification. Metering and billing costs clearly relate to facilities and activities which measure power and bill customers for their use of service. Neither the audit staff nor General Counsel's office perform either function.

Another suggestion offered by the ICP would be to functionalize costs pro-rata on the basis of line costs to generation and transmission. (McCullough, ICP, Exh. IO-18, p. 6) This suggestion would be easy to accomplish, but I believe its lack of precision would offer no improvement in the DES. However, the DES can be made less subjective and more precise. Limits in time and staff resources have not permitted a review of the methodology for this rate filing. Alternative methods will be reviewed for potential inclusion in the next filing.

Finally, the ICP testified that it is improper for BPA to functionalize exchange resource costs to transmission. They argue that exchange power should be treated as purchased power, which includes transmission costs in the unit cost of the resource. The ICP suggests that transmission costs included in the exchange resources provide the necessary generation-integration facilities for the delivery of the exchange resources to the BPA transmission system. (Deesen, ICP, Exh. IO-14, p. 9).

I reject this position for a number of reasons. First, BPA does not physically receive exchange power on the Federal transmission system in order to supply power to loads deemed by the Regional Act to be served by exchange resources. No changes are necessary in the operation of the Federal transmission system as a result of the execution of exchange agreements. Second, it is my view that the exchange transaction is an exchange of costs of resources, rather than a physical exchange of power that would result in greater use of transmission facilities. Finally, in order to comply with rate directives in Section 7 of the Regional Act, BPA recovers the costs of its resource pools from customers deemed for ratemaking purposes to be served by each resource pool, and not necessarily from those customers actually served by the resource pools. BPA purchases transmission resources from exchanging utilities, the costs of which are included in the average system cost BPA pays for exchange power (Metcalf, BPA, Exh. BPA-30, p. 12) BPA must recover those transmission costs from customers deemed by the Regional Act to be served by exchange resources. Exchange transmission costs are legitimate costs of transmitting exchange power, albeit not over the Federal Transmission System. These costs must be allocated as transmission costs to BPA's customers deemed to be served by the Exchange resource. I therefore have decided that it is reasonable for BPA to functionalize some exchange costs to transmission in order that they may be allocated as transmission costs.

D. Classification

1. Classification Methodologies

Once all costs are functionalized, those assigned to generation are classified to capacity and energy. Transmission costs are classified all to capacity. The classification of generation costs is based on the principle of cost causation. The various methods used for classifying generation costs between energy and capacity relate to the reasons underlying the need for the generation resources BPA uses to serve loads. The costs of facilities constructed to meet peak demand on the system are classified entirely to capacity. The costs of resources built or acquired to provide both capacity and energy are apportioned between those two components of power.

BPA incurs generation costs for different types of resources and programs. BPA's generating facilities consist of a mix of hydro and thermal resources. BPA also acquires exchange generating resources, and funds conservation programs that reduce the need to build and operate additional generating facilities. Since these major types of generation costs are incurred for different reasons, separate classification approaches are used. It has been suggested that this approach to classification is inappropriate, and that all generation costs should be classified by a single method applicable to all of BPA's resources. I do not believe that a single method can be applied to all of BPA's resources, and find it appropriate to examine the cost causation underlying each of BPA's major generation cost expenditures.

BPA classifies the costs of hydro generating facilities through an examination of the purposes for the components of the facilities. The costs of those portions of the hydro system installed solely for peaking capability are classified entirely to capacity. Costs associated with the portions of the baseload hydro system installed to provide both energy and capacity are classified on the basis of an examination of the operating characteristics of the hydro system. BPA first quantifies the amount of energy that can be produced continuously at critical streamflow levels by the hydro system operating at 100 percent plant factor. The power produced in this manner is available both instantaneously and over a period of time. Therefore, its cost is divided equally between energy and capacity. Any power that can be produced by the baseload hydro system in excess of this critical streamflow production capability is assumed to be available to provide capacity, but no incremental energy. These costs are classified exclusively to capacity.

Thermal resources available to BPA are classified on the basis of relationships developed in BPA's TDLRIC Analysis. This analysis examines the causes underlying resource construction and operation and develops measures of the least cost sources of capacity and energy in the long term. The TDLRIC Analysis indicates that the most economic source of capacity is a single cycle combustion turbine and the most economic source of energy is a baseload thermal plant (Exh. BPA-6, p.54). The analysis recognizes that each of these resource types provides both capacity and energy. To develop separate energy and capacity measures, the analysis credits the cost of the combustion turbine for the incremental energy produced and credits the cost of the baseload thermal plant for the capacity component. Based on this analysis, BPA's thermal classification indicates that thermal costs are primarily energy related.

BPA classified exchange resources on the basis of information supplied by exchanging utilities pertaining to how those utilities classify their own resources (Metcalf, BPA, Exh. BPA-30, pp. 3-14). Energy conservation costs were classified on the basis of the relative value of energy and capacity conserved. Resource acquisitions have been classified by the same methodology used for thermal costs.

A number of parties have objected to BPA's classification approach, or to certain aspects of BPA's classification methodologies. APAC, for example, has recommended that BPA use a fixed/variable approach in the classification of all of BPA's generation costs (Cook, APAC, Exh. PA-2, p. 10). This classification would assign all fixed generation costs to capacity, and all variable generation costs to energy. APAC argues that it is inappropriate to allocate any fixed costs to energy (Cook, APAC, Exh. PA-2, p. 11). APAC also argues that adoption of the fixed/variable classification would improve BPA's revenue stability. APAC indicates that if customers exhibit any degree of elasticity and reduce purchases in response to higher energy prices, BPA will suffer additional revenue deficiences in the future (Cook, APAC, Exh. PA-2, p. 19.)

I question the validity of the argument that the fixed/variable approach to classification of generation costs is appropriate for BPA. In the short run, all the costs that do not vary with output are fixed costs. The fixed/variable approach might be appropriate for a system that is primarily thermal, or for systems with a large thermal base and limited hydro peaking capability. However, it would not reflect the capacity and energy relationship developed during the planning of a hydro system such as the FCRPS prior to the inclusion of net-billed thermal projects. It would send an incorrect price signal concerning the relative costs of capacity and energy because the region is building thermal plants primarily to produce energy, not capacity. A witness for the state commissions stated in cross-examination that BPA's method is more appropriate than the method advocated by APAC (TR 3108).

The hydroelectric facilities of the FCRPS produce both energy and capacity. The FERC recognized this when providing guidance for calculation of the benefits for project justification in the Federal Power Commission P-35 manual for the Corps and Bureau projects. In the cost/benefit analyses for all FCRPS generating projects, both capacity and energy components are included. Values are then applied to the capacity and energy components based on alternative costs of generation. It would be inconsistent to recognize that costs and benefits are associated with both capacity and energy when planning the construction of hydro projects, but then assume after the project is constructed that costs associated with energy should reflect only the negligible operating costs of hydro plants.

Regional growth has promoted almost the full development of cost-effective hydro sites (Exh. BPA-6, p. 5). Thermal generation has been constructed to produce significant amounts of baseload energy, while peaking requirements have been met primarily through the construction of additional units at existing hydro projects. Presently, new energy requirements are being met primarily from purchases of the output of thermal plants, which also provide capacity.

The argument that energy intensive rates may result in an underrecovery of costs due to elasticity of energy prices is not convincing. I have seen no evidence that indicates that energy prices are either more or less elastic than capacity prices, and cannot definitively attribute the possibility of an underrecovery of costs to a decline in usage of one component of power over the other. For these reasons, I am not convinced that adoption of a fixed/variable classification methodology would result in greater revenue stability for BPA.

The ICP has recommended that BPA apply the results of its TDLRIC Analysis uniformly to classify all generation costs. The ICP contends that BPA's classification methods are ascribing excessive costs to capacity, and that BPA is signaling utilities to build additional capacity resources, with the potential that BPA may price itself out of the capacity market. Use of the TDLRIC Analysis classification percentages for all generation costs, the ICP claims, would send the correct pricing signals. (Shue, ICP, Exh. IO-17, pp. 9-12.)

Use of the thermal resource based TDLRIC Analysis percentages to classify costs related to the Federal hydro system would result in a change in the relative costs of energy and capacity, but would not reflect the differences in operating characteristics between thermal and hydro resources. For efficient operation, baseload thermal resources must be operated at high plant factors while hydro resources do not have this constraint for efficient operation. These differences in operating features along with the cost causation rationale cause me to question the strict use of thermal based classification percentages for costs associated with the Federal hydro system.

2. Hydro Classification

It has been suggested that BPA use the hydro classification method developed by the National Association of Regulatory Utility Commissioners (NARUC), for classifying baseload hydro plants (Cook, APAC, Exh. PA-2, p. 33). APAC claims that BPA's method for classifying baseload hydro is arbitrary, since there is no objective basis for the assumption that one-half of the hydro system's critical water capability is related to energy (Cook, APAC, Exh. PA-2, p. 33).

I disagree that the method used by BPA for classifying baseload hydro costs is arbitrary. I believe that BPA's division of the baseload hydro costs between capacity and energy reasonably reflects the costs of services provided by those facilities.

The NARUC method is of questionable applicability to BPA. An implicit assumption underlying this method is that energy produced under critical water conditions represents the allocation for capacity, while the additional output under median water conditions represents the allocation for energy. While the rationale for this method is not explained in the NARUC cost allocation manual, it appears that average megawatts produced under critical water conditions represent dependable capacity, and the difference between that figure and average megawatts produced under average water conditions represents energy. This method treats the cost of megawatts that meet firm load requirements as capacity only, and the cost of the remaining resource up to the output under average water conditions as energy only. BPA's hydro resource planning is based on the premise that sufficient resources must be available under critical water conditions to meet firm loads. Consequently, both capacity and energy requirements must be met from available resources under critical water conditions. Application of the NARUC classification method would be inconsistent with BPA's planning assumptions; therefore, I believe it would be inappropriate to use this method for classifying the costs of the FCRPS.

The WPUD's suggested that BPA underestimates the energy producing capabilities of the hydro system. They recommend that BPA use the ratio of average energy capability to peaking capability under similar water conditions. This method, they claim, would give an estimate of the percentages of facilities used to produce baseload energy requirements as opposed to additional costs incurred to produce maximum output (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, pp. 16-19).

The method suggested by the WPUD's fails to recognize that some hydro facilities are installed solely to meet peak demand. These facilities will produce no incremental energy over a given period of time. The amount of energy available from the system depends on streamflows, and not on the number of units available to generate the maximum output of the system instantaneously.

The ICP asserts that because streamflows are not even and continuous, it is not possible to capture the same number of average megawatts of energy as there are megawatts of capacity available during critical streamflow. 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 (Shue, ICP, Exh. IO-17, pp. 7-9).

The ICP has analyzed historic data relating to the highest critical period monthly energy available from the Federal hydro system. The reservoir storage capability of the Federal hydro system is large enough to capture all critical energy at what would amount to a 100 percent plant factor.

I agree with the assertion that operation of the hydro system to generate firm energy requires a level of generation during some periods in excess of the average generation. As noted by the ICP, the record does not quantify this excess. Although the ICP has included evidence which quantifies a proxy to this excess (Shue, ICP, Exh. IO-17, Attacment D), I would note that the proxy is an estimate. Of greater concern to me is the lack of information in the record to support classification of baseload hydro solely on operational characteristics. Classification for ratemaking purposes should consider operational needs during short periods of time, but other factors cannot be ignored. Although I am not resolving this issue in favor of the ICP in this rate filing, I do believe that future rate filings should continue to pursue appropriate classification methodologies.

3. Thermal Classification

The PGP advocates the use of a modified version of the baseload hydro classification formula for classification of thermal resources (Garman, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, pp. 10-13). The formula they advocate would divide one-half of the product of the nameplate capability of all thermal plants and the plant factor of those plants by the nameplate capability to determine the capacity classification percentage. They argue that use of this formula would overcome inconsistencies in BPA's current method for classifying thermal plants. These inconsistencies, they claim, result from BPA's use of numerous methods for classifying its generation costs. The PGP contends that the formula they propose is superior to BPA's application of the TDLRIC Analysis results for thermal classification. Their classification method is based on information related to actual generation plants BPA will be bringing online in the future and, therefore, would not be subject to the unpredictable nature of fuel prices and inflation rates in long run incremental cost studies (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 10-13).

BPA has developed different cost classification methodologies for hydro and thermal resources to reflect the differences in the operating characteristics of each type of plant, and the opportunities available for having a mix of such resources. I do not find it inconsistent to apply different cost classification approaches to reflect the relative costs of the resources, given the nature of BPA's mix of generating resources. The formula proposed by the PGP is not a cost-causation approach. It examines strictly the capability of the thermal plants and how they are operated, and fails to consider current cost-effective alternatives for providing increments in thermal capability for both capacity and energy. The TDLRIC Analysis used by BPA does recognize the cost of adding increments or avoiding costs by not adding those increments. Therefore, the TDLRIC Analysis classification approach is preferable to the proposed PGP method.

The PGP has objected to use of BPA's TDLRIC Analysis as a basis for classifying thermal costs. They claim that such a classification unfairly discriminates against BPA's high load factor customers (Garman, Opatrny, Knitter, and Sunday; PGP, Exh. PB-20, pp. 24-26).

BPA's TDLRIC Analysis recognizes that thermal plants are being added primarily to provide energy for the region. Although new thermal plants add capacity as well as energy, the need for capacity is not the critical cause underlying their construction (Exh. BPA-5, p. D-4). High load factor customers impose both energy and capacity requirements. It is the energy component of their requirements that must be met by increasingly expensive increments of generation resources and, therefore, I do not believe that use of the TDLRIC Analysis classification unfairly discriminates against these high load factor customers.

The DSI's argue that if BPA used the peak credit method in developing a TDLRIC Analysis based on a coal plant, with low capital costs and high operating costs relative to a nuclear plant, the classification percentages would attribute a large majority of costs to capacity, the balance to energy. BPA used a nuclear plant in its evaluation of incremental costs in the TDLRIC Analysis (Carter, DSI, Exh. DS-5, pp. 10-15).

The DSI's suggested a deficiency in the application of the TDLRIC Analysis results in the March 1982 Cost of Service Analysis, rather than totally discrediting the TDLRIC Analysis results themselves (Shue, ICP, IO-29, p. 2-5). In the initial COSA, the variable costs were classified exclusively to energy and the TDLRIC Analysis classification percentages were applied to the fixed costs. Use of a coal plant in the TDLRIC Analysis, coupled with the application of those results to the fixed costs in the COSA would produce erroneous economic indicators with respect to the relative incremental costs of capacity and energy (White, OPUC, Exh. SC-6, pp. 7-9). I believe that in order to avoid sending incorrect pricing signals, the COSA should apply classification percentages developed from the combined fixed and variable TDLRIC Analysis results to the combined fixed and variable costs of resources being classified in the COSA (Shue, ICP, Exh. IO-29, pp. 2-5). I have included this change in the COSA for the final proposal.

4. Exchange Resources

BPA has requested information from exchanging utilities relating to the classification of the resources which they exchange. The classification percentages of those utilities responding to BPA's request were weighted and used to develop overall classification percentages applicable to exchange generation costs (Metcalf, BPA, Exh. BPA-30, pp. 13-14).

The DSI's have argued that the classification percentages developed by BPA for the exchange may not be based on cost causation. They assert that the purposes for which exchanging utilities developed classification may vary, and the data BPA received did not cover all exchanging utilities, and the data was not verified by BPA (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 21 and pp. 25-28; Carter, DSI, Exh. DS-4, p. 29).

The DSI's further contend that the cost causation of the purchaser (BPA) should govern the classification of resources, and that the cost causation of the seller (the exchanging utilities) should not be a deciding factor in BPA's classification of the exchange resource. They suggest that BPA should examine the Average System Cost (ASC) submittals to determine the hydro and thermal content of their systems and apply BPA's own hydro and thermal classification percentages to the resources of the exchanging utilities (Carter, DSI, Exh. DS-4, p. 29-32).

Alternatively, the DSI's suggest that the proper classification for exchange resources is use of the classification percentages of the FBS. They suggest that the FBS percentages are reasonable proxies for the classification percentages that might be developed from an exhaustive evaluation of the character and operation of the exchange resource (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 28).

Until further supporting information about the character and operation of the exchange resources is available, I believe that it would be speculative to assume that BPA's classification of FBS resources also are applicable to exchange resources.

Individual exchanging utilities plan their resources on the bases of load requirements and the most economical resource alternatives available to them. These factors may be different for the individual exchanging utilities than they are for BPA. An examination of the exchanging utilities' ASC submittals, and the application of BPA's hydro and thermal classification percentages to the corresponding types of exchange resources would expedite the classification procedure, but I believe would not yield accurate results. More information relating to cost causation of exchanging utilities is required for a proper classification of exchange resources than is contained in the ASC submittals. The additional information required relates to load growth patterns and operating and planning criteria used by these utilities The IOU's were aware that the classification percentages that they were asked to provide would be used in BPA's rate development process (Exh. BPA-5, Attachment 1, p. 191). I believe that the utilities themselves are better able than BPA to develop classification percentages for their own resources. I am willing to accept their classification of their own resources, so long as such classification pertains to their ratemaking functions.

BPA purchases exchange resources at the price and in the quantity that such resources are offered. Additionally, BPA neither operates nor plans the availability of exchange resources. Moreover, the exchange does not involve a physical transfer of power, but only an exchange of resource related costs. For these reasons, I believe that it is appropriate to use the exchanging utilities' classification percentages for the exchange resources.

5. Transmission Costs

It has been suggested that BPA classify a portion of its transmission costs to energy to reflect costs incurred to reduce line losses (Drummond, IPUC, Exh. SC-4, p. 7; Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, pp. 20-21). I agree that it is appropriate to classify those transmission costs to energy that are expended to reduce transmission energy losses. However, it is difficult to make a clear distinction between costs incurred to increase the capabilities of the transmission system and costs incurred to reduce line losses. Neither the BPA staff nor any party have developed a study which reasonably supports the adoption of a methodology for classifying transmission costs to energy. For this rate filing, and until such time as a clear methodology for a different classification of transmission costs is proposed, I find no reason to deviate from the method BPA has used to classify transmission costs.

6. BPA Administrative Costs

BPA has classified its own administrative and general costs on the basis of the classification of all other generation annual costs. The PGP contends that it is inappropriate to include as purchased power costs the costs of non-operating resources such as the Supply System plants 1, 2, and 3 in the determination of classification of BPA overhead costs (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, p. 15-16; TR. 2863-4).

This suggestion, if adopted, may result in an inaccurate classification of BPA overhead costs. The costs related to the Supply System plants 1, 2, and 3 were classified to reflect the cost causation which resulted in their construction. Although these resources are not yet operational, I believe it is reasonable to consider their costs when classifying BPA overhead costs. The parties acknowledge that overhead costs include costs of administering the construction of those plants (TR 2863-2864). I believe that there is a direct relationship between the classification of all of BPA's generating resources, whether operating or not, and the classification of BPA's overhead costs.

E. Seasonal Differentiation

BPA seasonally differentiates energy costs on the basis of energy produced from withdrawals of stored water from the reservoirs.

Capacity costs were seasonally differentiated according to the probabilities of negative margin (PONM) calculated by the TDLRIC Analysis. Transmission costs were not seasonally differentiated.

The WPUD's have suggested that it is inappropriate for BPA to include the energy produced from storage in total firm energy loads when calculating the percentages used to seasonally differentiate energy costs. They claim that energy produced from storage has been double counted in BPA's calculation. (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-3, p. 8.)

Apparently the WPUD's do not understand the relationship between storage-related and nonstorage-related costs (TR 5517-5521). Total firm energy loads are served by power produced from water driven generators in the dams. Water is stored in reservoirs behind some dams so that it may be used when needed to generate power. All water flowing through a dam will generate power, whether it was stored or not. Costs associated with storage facilities do not include costs of generating power. In order to seasonally differentiate storage costs, BPA used the amount of power produced from storage during the winter and summer months. This same amount of power produced from storage is included in the total firm energy loads served in each season. The seasonal percentages of total firm energy loads were used to seasonally differentiate non-storage related costs. The combined seasonal differentiation of storage and non-storage costs was applied to seasonally differentiate all energy costs.

No double counting has taken place by including the energy produced from storage in the total energy produced to serve seasonal loads. All water, stored or not, must flow through the generators to produce power. The costs associated with the non-storage facilities are generation costs. All water flows through the generators, and all kilowatthours are produced by the generators. The costs of the generation facilities used in the seasonal differentiation of nonstorage costs do not include the costs of storage facilities, which, by themselves produce no energy. If the storage facilities produced their own energy, there might be a double counting. However, storage facilities only contain water that subsequently is used to generate power by the non-storage (generating) facilities. The amount of energy produced from storage is a subset of total kilowatthours produced, not a separate amount of energy produced by the storage facilities themselves.

APAC has suggested that BPA should recognize that thermal generation varies as a result of monthly differences in amounts of power generated and fuel mix associated with generation. APAC recommends combining thermal and hydro seasonal differentiation. (Cook, APAC, Exh. PA-2, pp. 27-28.)

BPA adds thermal resources to supply needed energy on an annual basis under critical water conditions. Increases in a 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. 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 its seasonal energy loads, I believe that it is appropriate to seasonally differentiate costs on the basis of withdrawals from storage. In addition, seasonal differences in BPA's thermal costs, on a planning basis, are non-existent (Exh. BPA-6, p. 9-10).

A number of parties have indicated that BPA should not seasonally differentiate capacity costs using probabilities of negative margin. The WPUD's claim that the PONMs fail to consider changes in the operation and planning of power supply facilities. They recommend that BPA use a probability of contribution to peak (PCP) method to seasonally differentiate capacity costs (Saleba, Russell, Schneider, and Hutchinson, WPUD, Exh. PB-15, p. 19-33).

The probability of contribution to peak method for seasonally differentiating capacity costs only looks at loads placed on the system. Because the PONM method looks at both loads and resources available to serve those loads, I believe it is a better method for seasonally differentiating capacity costs.

APAC has argued that use of PONM does not have a one-to-one relationship with capacity costs and reduces the results to speculation (Cook, APAC, Exh. PA-2, pp. 22-27). I do not agree that the results of a PONM analysis are speculative. These results provide an indication of the contribution of seasonal loads to BPA's need to acquire additional resources. I believe that the PONM results provide a basis for the establishment of a pricing structure that sends the proper economic signals to users of capacity. A further discussion of the rationale behind the PONM analysis is contained in Section V.E. of the Record of Decision.

A question has been raised as to whether transmission costs should be seasonally differentiated. BPA did not seasonally differentiate transmission costs because studies have found that there is little difference in stresses placed on the transmission system throughout the year (Revitch, BPA, Exh. BPA-31, p. 14).

The PPC has recommended that all fixed costs of the Intertie be allocated to the April to June spill period (O'Meara, PPC, Exh. PB-11, p. 11). However, the Intertie costs are incurred to provide service throughout the year. Moreover, it is doubtful that assignment of higher costs to the Intertie during peak use periods would alleviate saturation during that period. For these reasons, I do not agree that special cost allocation treatment should be given to the Intertie segment for the April through June period.

F. Allocation of Costs

1. Generation Capacity Costs

For capacity cost allocation, BPA has identified the extent to which each rate pool's capacity requirements are served by each of BPA's three resource pools. In the initial COSA this identification was made through an examination of the rate pools' energy requirements served by each of the resource pools. It was assumed in this approach that the amount of capacity provided to the rate pools by the resource pools bears a direct relationship to the amount of energy provided.

The WPUD's have objected to this method of assigning resource pool capacity costs to the rate pools. They argue that the assignment of resource capacity costs to the rate pools on the same basis as service of energy loads from each resource pool is inconsistent with BPA's cost causation approach to ratemaking. Additionally, they argue that energy consumption from the resource pools is a poor surrogate for determining how resource pool capacity costs should be allocated to the rate pools. (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, p. 11.)

The DSI's have argued that the assignment of resource pool capacity costs to the rate pools is inappropriate for a number of reasons. First, they claim that such an assignment of capacity costs is very sensitive to the energy load/resource balance, and results in wide swings in cost allocations with small changes in the energy load/resource balance. They argue that the method used by BPA requires arbitrary assumptions to be made which can significantly affect the results. Furthermore, they claim that BPA's method produces results that are internally inconsistent and fail to account for all capacity resources (Drazen & Schoenbeck, DSI, Exh. DS-5, p. 17).

I have reviewed six methods proposed for allocating resource pool capacity costs to the rate pools (Drazen and Schoenbeck, DSI, Exh. DS-5, Appendix B). Four of these methods require that capacity loads and resources be quantified and compared. Two do not. The proposed methods are:

(1) A uniform allocation of capacity costs to customer classes could be used. This would be achieved by dividing total capacity costs by total capacity loads. This method is administratively simple to implement, and requires neither a quantification of resource pool capacity availability nor a comparison of loads and resources.

(2) Capacity costs could be allocated to the rate pools on the basis of energy received from the resource pools. This method requires only that energy loads and resources be quantified, and an energy load/resource balance be prepared to identify the portion of each rate pool's load served by each resource pool. Capacity costs would be allocated in those proportions developed by an examination of the energy availability from the resource pools. This method was used in BPA's initial proposal.

(3) Available capacity from the resource pools could be quantified and compared to capacity loads. Capacity available from the resource pools could be assigned to the rate pools on the basis of the cost recovery priorities of Section 7(b)(1) of the Regional Act. Any resource pool capacity in excess of total loads then could be assumed to be sold independently to recover the costs of the excess.

(4) Capacity available from the resource pools could be quantified and compared to capacity loads. Available capacity from the

resource pools could be assigned to the rate pools on the basis of the cost recovery priorities of Section 7(b)(1) of the Regional Act. The costs of any excess capacity could then be recovered by assigning the excess pro-rata to the rate pools on the basis of their loads relative to total loads.

(5) Capacity available from the resource pools could be quantified and compared to capacity loads. A capacity load/resource balance could be achieved by assigning excess capacity costs to the resource pools pro-rata on the basis of the size of each resource pool relative to total available resources. This result could be achieved by "scaling down" each resource pool by the ratio of total capacity loads to total capacity resources. This method assumes that excess capacity is attributable to all resource pools.

(6) Capacity available from the resource pools could be quantified and compared to capacity loads. A capacity load/resource balance could be achieved by "scaling down" all resources except the exchange. This method assumes that none of the excess capacity is attributable to the exchange resource and, therefore, would not be allocated to the rate pools to the extent that they rely on exchange resources.

The WPUD's have recommended that I adopt method (3) above, which allocates resource pool capacity on the cost recovery priorities of the Regional Act and assumes that the cost of excess capacity would be recovered through independent sales (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, p. 12.) This method involves a degree of risk which has not been fully analyzed. The excess capacity that is assumed to be sold under this methodology is BPA's highest cost capacity (TR. 2708). There is little expectation that BPA can sell this excess capacity at its fully allocated cost and there is evidence on the record that it would not be an easy task (TR. 2710). An inability to sell this excess would result in underrecovery of costs. Because the risk of underrecovery of costs appears significant although it has not been fully analyzed, and because one of my objectives is to maintain BPA's fiscal integrity, I am unwilling to assume such a risk.

The DSI's have proposed that BPA adopt method (4), which allocates the cost of excess capacity to the rate pools pro-rata on the relative size of each rate pool's load to total loads (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 19-20.) The costs of excess capacity that would be allocated to the rate pools are a melding of exchange resource and new resources costs. BPA has agreed to enter into a settlement with its customers with respect to its Power Sales Contracts litigation. One of the provisions of this settlement is that no unrecovered cost of the exchange resources will be allocated to the preference customers purchasing from the 7(b) rate pool. Adopting method (4) as proposed by the DSI's may be in violation of this settlement provision, and therefore I am cautious about accepting this method for allocating capacity costs to the rate pools.

The DSI's alternatively suggest adopting method (1), which uniformly allocates capacity costs (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 18-19). I have examined the consequences of allocating capacity costs on a uniform basis and find that it would tend to destroy the identity of rate pools. Therefore, for this rate filing, I do not feel there is sufficient justification to adopt method (1).

Method (2), the capacity cost allocation based on energy load/resource comparisons, proposed by the BPA staff, assumes that capacity and energy requirements of the rate pools are met by the resource pools in a directly proportional basis. Therefore, capacity costs are allocated in direct proportion to the allocation of energy costs. I am not convinced that such a proportion exists, particularly since there are resources and classes of service with which either energy or capacity, but not both, are associated. I believe that the energy and capacity requirements of the rate pools can be treated independently. Therefore, it is more appropriate to use a method which uses capacity measurements for allocation of capacity costs (TR 2706).

With respect to method (6), 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.

One of my greatest concerns in the allocation of resource pool capacity costs is the allocation of the costs of any potential excess capacity. Some of the proposed methods ignore the existence of excess resource capacity. Because capacity loads and resources are not normally planned to precisely balance, it is necessary to examine the origins of the excess capacity. BPA plans acquisition of resources primarily to provide energy for the region. In the course of acquiring energy resources, capacity resources also are added, frequently in excess of the added capacity loads. We are currently unable to rigorously trace the origins of excess capacity to each individual resource pool because the nature and amount of the excess are not easily determined (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 18). Therefore it is reasonable to assume that excess capacity is supplied by each resource pool in the proportion of its size to the total available capacity resources. I have adopted method (5) which attributes the origin of excess capacity to the resource pools on the basis of their relative sizes. By "scaling down" the capacity in each pool, there are no unallocated capacity costs. This assures that the public agency customers need not pay for any unrecovered exchange capacity costs. The only exchange capacity costs the public agencies must pay under this approach are their pro-rata share of FBS and Exchange capacity costs associated with the 7(b) loads.

2. Energy Conservation Costs

In the initial COSA, BPA proposed that the costs associated with funding and operating its energy conservation programs be allocated to customer classes on the cost-follows-savings method. Because funding of conservation programs in the region is available to all utilities, whether or not they purchase power from BPA, it would be possible for a utility which does not purchase power from BPA to receive conservation funding without having an obligation to pay anything in return through rates. Therefore, rather than recovering all costs associated with conservation funding through rates applicable to BPA power sales, the conservation costs incurred by BPA were divided into two portions.

One portion would be recovered through contractual provisions with utilities receiving conservation funds, whether or not they purchased power from BPA. This portion would be recovered from utilities by charging up to the wholesale power rate (less an incentive) for an imputed savings of energy or capacity. The balance of the conservation costs would be recovered through the rates. Program costs related to savings achieved by the preference customers of BPA and the IOU's purchasing power from BPA were identified. It was assumed that the costs of conservation performed by preference customers were associated with a reduction in loads placed on the Federal base system. Savings achieved by the IOU's were assumed to result in a decreased need for BPA's purchase of new resources, and therefore costs associated with such IOU savings were attributable to the new resources pool. No savings were directly attributable to the DSI loads. However, BPA assumed that exchanging utilities would include their conservation program costs in their ASC and the DSI's would be allocated conservation costs indirectly in this manner.

The PGP, EWEB, APAC, the PPC, the ICP and other parties objected to BPA's proposed method for allocating conservation costs because they asserted that the DSI's benefit from BPA's conservation programs in the region and should be obligated to pay a proportionate share of the costs (Waldron, PGP and EWEB, TR 1486-1487; Garten, APAC, TR 1510-1512; Sugden, PPC, Exh. PB-13, pp. 1-2; Garman, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, pp. 65-67; Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. 16, pp. 33-42; Illich, ICP, Exh. IO-16, pp. 4-12; Carver, OPUC, Exh. SC-3, pp. 1-10). The PGP argued that conservation by 7(b) customers of BPA places a reduced load on the FBS, thus making more of it available for service to the DSI's, and benefiting them without requiring them to make any direct payment (Garman, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, p. 66). Another problem suggested in BPA's method was that for the FY 1983 test year, the IOU's were expected to purchase little or no power from BPA, and thus conservation costs allocated to the 7(f) rate pool possibly would be unrecoverable by BPA.

The PGP, EWEB, the ICP and OPUC argued that BPA's inclusion of a contract charge in the conservation cost allocation method is a disincentive to utility participation in BPA's conservation programs (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, pp. 65-67; Reeder, EWEB, Exh. PB-17, pp. 4-5; Illich, ICP, Exh. IO-16, pp. 4-12; Carver, OPUC, Exh. SC-3, pp. 1-10). Because conservation results in a reduction of loads, and because some utilities have relatively high fixed costs, this reduction in load would cause a decrease in revenues under current rates available to meet the fixed costs of a conserving utility. The conserving utilities then would have to increase rates after the conservation had taken place. The contract charge as proposed would exacerbate this problem at the retail level. The BPA staff indicated that it would be difficult to incorporate a contract provision which would implement the contract charge in time to assure recovery of costs in FY 1983 (TR 4936-4945).

BPA's proposed method for allocating conservation costs recognizes that a conserving utility usually has some economic incentive to perform conservation measures. For the measures that are not economic to the utility, BPA should subsidize conservation measures to the extent that they are not cost effective for the utility in relation to the wholesale rate they pay for power but still cost effective for BPA. The proposed method for recovering conservation costs generally was developed to mitigate potential adverse utility reactions to BPA proposed conservation programs. The contract charge was designed to achieve four specific objectives: (1) to insure that BPA's rates will not be higher because conservation, rather than a generating resource, was used to serve load growth; (2) to assure that utilities do not unfairly pay through BPA rates for a conservation benefit accomplished in another utility's service area who may place either no load or a small load on BPA and, therefore, be required to pay through BPA rates either nothing, or a disproportionately small share of the costs of the conservation benefit; (3) to separate and thereby focus on both the allocation/cost recovery and incentive payments necessary to achieve conservation; and (4) to introduce the concept of not relying on BPA ratepayers alone to recover all the costs of conservation in the region.

Although the contract charge for conservation program costs addresses questions of equity in cost recovery from both participants and non-participants in BPA's conservation programs, and questions of equity between generators and non-generators who are BPA customers, as proposed this feature of BPA's initial rate proposal received no support from any of BPA's customers. Although other forms of a contract charge were suggested, we feel any such charge should only be implemented as a part of a more complete program which adequately addresses the utilities' fixed cost problem. For this reason, and because of the unlikelihood of incorporating a chargeback provision in the conservation contracts applicable to cost recovery in FY 1983, I believe it reasonable that the contract charge provision for recovery of BPA conservation costs should be eliminated in this rate filing.

The PPC, DSI's, and EWEB have expressed support for allocating BPA conservation costs using the cost-follows-benefits method (Sugden, PPC, Exh. PB-13, pp. 4-5; Schoenbeck, DSI, Exh. DS-9, pp. 1-4; Reeder, EWEB, Exh. PB-17, pp. 1-13). This method would require the development of two separate sets of rates: one with the loads unadjusted for conservation, which would be hypothetical, and another with loads and costs adjusted for conservation, which would represent the actual. The difference between the two rates would represent the benefits of conservation to the customers paying these rates. The conservation costs would be allocated to rate classes in the proportion of their benefits to total benefits achieved. This method is very rigorous and administratively difficult to implement, and the BPA staff believes that it could not implement the cost-follows-benefits method for this rate filing. EWEB recognizes this and has suggested that, while the issues related to allocation of conservation costs are being addressed, BPA should adopt the cost-follows-BPA loads method. The PGP supports EWEB in this recommendation (Reeder, EWEB, Exh. PB-17, pp. 1-13; Garmen, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, pp. 65-67; Opatrny and Reeder, PGP, Exh. PB-25, pp. 13-18). The cost-follows-BPA loads method allocates conservation costs evenly over all BPA loads and is simple to administer.

The WPUD's and the PNGC have suggested that BPA allocate conservation costs using the cost-follows-regional loads method. (Saleba, Russell, Schneider, and Hutchison, WPUD, Exh. PB-15, pp. 33-42; DSI Opening Brief, pp. 72-73; Johnson, PNGC, EXh. PB-29, pp. 1-9). The DSI's have also essentially supported a cost-follows-Regional loads methodology for this proceeding, but only as an interim allocation method. This method recognizes that all power consumers in the region would benefit from BPA conservation expenditures. It does specifically address inequities that could result from a utility not paying its proportionate share of conservation costs which result from the EWEB/PGP recommendation. However, it may not adequately recognize that BPA loads will benefit in a way in which non-BPA loads do not. Also, it too requires the implementation of a contract charge to recover costs from non-BPA customers.

Each of the methods proposed has positive features that address most of the inequities identified. Yet, none appears to adequately address all the important issues raised by the parties. The implementation of the cost-follows-benefits method is not possible for this rate filing because of its difficulty, and any method utilizing a contract charge also is not possible to implement for FY 1983. Therefore, I have decided that the EWEB/PGP suggestion to use the costs-follow-BPA loads method would be a reasonable and appropriate method to use for the allocation of conservation costs. This method minimizes the risk of BPA underrecovery of costs because it does not require a contract charge. It does not exacerbate the lost revenue problem at the retail level, and is easy to understand and implement.

I recognize that this method does not achieve absolute equity between participants and nonparticipants or between generating and nongenerating utilities. I intend to continue searching for practical ways to address these problems, either through the conservation funding and associated contracts or the rates process or a combination of the two.

3. Energy Load/Resource Balance

A number of parties have suggested that it is inappropriate to increase exchange loads and the exchange resource by losses. The JCP indicates that no transmission losses occur on the Federal Columbia River Transmission System in the exchange (Allcock & Wolverton, JCP, Exh. JCP-3, p. 10). The WPUD's also assert that there is no flow of electricity on BPA lines as a result of the exchange and therefore no losses could be experienced in the exchange transaction (Saleba, Russell, Schneider, and Hutchinson, WPUD, Exh. PB-15, p. 13).

I agree that the exchange transaction causes no flow of electricity and no losses on Federal transmission lines. However, the Average System Cost methodology requires that exchange power be measured at the point where an exchanging utility's transmission lines meet that utility's distribution system. To make this measured amount consistent with other BPA load and resource measurements, transmission losses are added. Thus, both exchange load and exchange resource are stated at the generation level. I accept the evidence presented that this is the correct treatment for exchange power in the allocation of costs (Revitch, BPA, Exh. BPA-68, pp. 1-2). BPA pays for transmission losses in the ASC of the exchange. If transmission losses were not accounted for in the load/resource balance, the size of the exchange load and resource would be incorrectly stated, and this would result in an incorrect allocation of cost.

In the development of the load/resource balances used to allocate costs, BPA has shaped the production of energy from the Federal hydro system over time into periods when it would be most marketable. This shaping of energy has not included energy from the latter half of April, all of May and June 1983. BPA has not shaped energy out of that time period so that sufficient water will be in the reservoirs to enable BPA to provide flow necessary for the migration of anadramous fish without affecting reservoir operations for the rest of the year (Pollock, BPA, Exh. BPA-61, p. 7).

4. <u>Transmission Costs</u>

The ICP has expressed concern that BPA may have allocated transmission costs incorrectly to the customer classes. They contend that BPA takes delivery of exchange power on Federal transmission lines and delivers this power to the ultimate user over the Federal transmission system. The ICP claims that transmission costs are included in the ASC of exchanging utilities for transmitting power from their generation facilities to the BPA transmission system. Therefore, they contend that the rate pool being served by the exchange resources should be allocated Federal transmission costs in addition to the transmission costs already included in the ASC of exchange power (Deesen, ICP, Exh. IO-14, p. 10).

I do not subscribe to this view of the exchange transaction. There is testimony supporting the view that the exchange is a transaction involving the exchange of resource-related costs rather than an exchange of generation resources that need to be linked between parallel transmission systems (Wolverton and O'Meara, PPC, Exh. PB-32, p. 6). No exchange power is delivered to the BPA transmission system and, therefore, no additional stresses are placed on the BPA transmission system. Loads that are deemed to be served by exchange power pay the generation and transmission costs of the exchange, despite the fact that they may be receiving power that is actually transmitted over Federal transmission lines. The exchange load is included in Section 7(b) loads and is served at the priority firm rate, which includes the cost of Federal transmission facilities, despite the fact that these loads actually receive power which may never flow over Federal transmission facilities. On close examination, I find the ICP argument to be internally inconsistent. In attempting to reconcile the allocation of costs with physical flows of power, they make the assumption that exchange power flows only in one direction; from the exchanging utilities to the load deemed to be served by exchange resources. The ICP makes no assumption concerning flows of Federal power sold at the priority firm rate to the exchange load. I have found that the record contains little evidence allowing a clear reconciliation of actual flows of power with designated uses of the transmission system. Consequently, I believe that it is appropriate for BPA to assume that for cost allocation purposes, Federal transmission costs should be paid by customers placing loads deemed to be served by Federal generating resources. In turn, I believe exchange transmission costs should be paid by customers placing loads that are deemed to be served by exchange generating resources.

5. <u>BPA Overhead Costs</u>

The DSI's claim that it is inappropriate for BPA to allocate its overhead costs to loads served by exchange resources. The rationale for this argument is that BPA's overhead costs relate to administration of the FBS, and that exchange costs include overhead of the exchanging utilities. This, they contend, amounts to double counting of overhead costs (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 29).

Provisions of Sections 7(b) and (c) of the Regional Act address the recovery of resource pool related costs. Section 7(g) of the Regional Act relates to the recovery of costs not specifically identifiable with resource pools. I believe that BPA overhead costs are not specifically identifiable with respect to individual resource pools and I find it appropriate that such costs be allocated to all customers on the basis of their loads relative to total BPA loads. I also believe that administrative costs included in the ASC of exchange resources is a legitimate portion of the cost of the exchange. The recovery of this cost as a resource-pool-related cost is directed specifically by the Regional Act. For this reason, I cannot agree that there is double counting in the recovery of BPA administrative costs from loads served by exchange resources.

6. <u>Exchange Costs</u>

The ICP has proposed that the average cost of exchange resources be allocated to the rate pools on the basis of energy, and once allocated, then classified between energy and capacity (Deesen, ICP, Exh. IO-14, p. 8). This treatment of the exchange would be inconsistent with generally accepted ratemaking principles. The exchange provides both energy and capacity, as do other resource pools. The ICP does not explicitly advocate that FBS and new resources costs be assigned to rate pools on an energy basis and then classified between energy and capacity. BPA's other resource pools are first functionalized, then classified. Energy and capacity costs are allocated separately based on the needs of the rate pools for each component of power. I am concerned that treating the exchange in the way suggested by the ICP may violate the principles of ratemaking by not recognizing the relative costs of energy and capacity provided by the exchange to the rate pools.

7. <u>Transmission Services Agreement Costs</u>

BPA considered three methods of allocating the costs of the transmission services agreements (TSA's) contemplated by the settlement of the public agency Regional Act lawsuit.

The first method would allocate costs to the 7(b) rate pool. The second method would allocate to all loads served by exchange resources. The third method would be to allocate to all loads (Revitch, BPA, Exh. BPA-68, p. 3). I have adopted the first method because, as argued by the CEC, the 7(b) pool is the primary beneficiary of this alternative to treating public agency exchanges of transmission as loads and resources (CEC Reply Brief, pp. 11-12). Although as argued by WPUD's (WPUD Opening Brief, p. 24) the transmission services agreement is associated with the exchange, I believe the beneficiaries of the reduction in allocation of exchange resources -- the 7(b) pool, should equitably bear the nominal costs associated with the sizeable benefits.

G. Supplementary Issues

1. Normalization Adjustment

The volatility of purchased power costs as a result of funding construction of Supply System plants 1, 2, and 3, has caused BPA to adopt the process of "normalizing" purchased power costs. Normalization compares the present values of purchased power costs over the lives of the Supply System plants with the present value of BPA's revenue stream. The difference between the present values of these cost streams is the normalized cost for purchased power. This "normalized" amount is compared with the forecast expenditures for purchased power in the test year. Any difference between the normalized amount and the forecast amount is treated in the COSA as an annual cost (it could be either positive or negative). The amount represented in the COSA is not an additional revenue requirement, but simply a mechanism for providing stability to the net repaymemt requirement (the difference between total revenue requirements and annual costs). If the process of "normalizing" the purchased power costs was not performed the amount of the normalization adjustment would be included in the net repayment requirement. This would cause fluctuation from year to year in the net repayment requirement percentages applied to different types of investments. Because the normalization adjustment is treated as an annual cost in the COSA and is directly related to the Supply System plants, it is classified between capacity and energy by use of the same classification method applicable to the Supply System plants. If the same amount appeared in the net repayment requirement, it would be related to the FBS hydro and Federal transmission investments, which are classified by a different method. Thus, this would result in a distortion of the classification of costs.

The ICP contends that the normalization adjustment is a mislabeling of BPA's cost. They claim that the normalization adjustment makes the rate filing more difficult to read, and that it does not add legitimacy to the process. They recommend that this adjustment to annual costs be eliminated (McCullough, TR. 5686).

I believe that because purchased power costs related to net-billed Supply System plants have stabilized sufficiently, the normalization adjustment to the COSA annual costs is no longer needed. Therefore, it has been eliminated from BPA's final rate proposal.

2. Exchange Cost Estimates

BPA requested exchanging utilities to provide estimates of their Average System Cost and exchange loads for FY 1983. All exchanging IOU's except Puget Sound Power & Light (PSP&L) have provided this information. BPA estimated PSP&L's ASC for the test year and has used the estimates of ASC provided by the other utilities themselves in the estimate of total exchange costs.

By using this estimation process, the DSI's contend that BPA has overestimated the cost of the exchange. Specifically, they contest BPA's exchange cost estimates for PSP&L, Portland General Electric Company, Idaho Power Company, and the Cities of Du Bois, and Soda Springs, Idaho. BPA's estimates, which the DSI's contest, are summarized on Revised COSA Table A-1.

With respect to PSP&L's projected ASC, the DSI's claim that a 25.5 mill ASC is a gross overestimate of the cost of PSP&L's exchange power (DSI, Opening Brief, p. 3.) They cite that PSP&L's current ASC approved by BPA is only 19.86 mills, and after a power cost adjustment, effectively only 18.72 mills. Furthermore, they cite that PSP&L has no rate increase application pending, and that even if such an application were pending, the state of Washington has an 11 month suspension period, so that it is highly unlikely that PSP&L could obtain rate relief prior to May or June of 1983. The DSI's suggest that BPA could reasonably assume in its estimate that PSP&L's ASC would remain at its 18.72 mills level for the months of September through December, 1982. Thereafter, the DSI's suggest that BPA could reasonably assume that the base rate of 19.86 mills would be in effect from January through May 1983. The DSI's suggest that on June 1, 1983, BPA could reasonably assume an increase of PSP&L's ASC to 22 mills which would be effective for the months of June through September, 1982. I presume they mean June through September 1983. Such assumptions would produce a weighted estimate for FY 1983 at 20.19 mills per kWh for PSP&L's exchange costs, rather than the 25.5 mills that BPA has estimated (DSI Opening Brief, p. 4).

BPA estimated PSP&L's ASC on the basis of historical increases in their rates. Applying an historical percentage to PSP&L's current ASC on file with BPA produced the 25.5 mills ASC estimate for FY 1983. It should be noted that this is the only projection BPA made for any utility's ASC, since Puget is the only company that supplied no exchange cost estimate themselves. I believe that it may have been inappropriate to apply an historical growth percentage to PSP&L's ASC. Moreover, I believe that the DSI suggestion for estimating Puget's ASC is, with some modification, a reasonable method for BPA to use for estimating ASC of exchanging utilities that do not supply their own estimates. I find that it would be appropriate to use the most current ASC filing approved by BPA, which, as of July 19, 1982, was 19.48 mills for PSP&L as a basis for a projection. This projection must recognize the effects of an increase in BPA's rate to the exchanging utility effective October 1, 1982. PSP&L is expected to purchase 68 average megawatts of WNP-1 exchange power from BPA. This would raise their contract system cost by approximately $4 million, resulting in an increase in the range of a 1.5 percent to their ASC. Such an increase would be in effect from October 1 1982, until June 1, 1983, at which time I would find it reasonable that their ASC would increase to 23 mills. These assumptions would yield a weighted ASC for Puget during FY 1983 of 20.85 mills (COSA Documentation, p. 120).

I believe that this may reflect a more reasonable estimate for Puget's ASC than what BPA proposed in the rebuttal testimony (Revitch, BPA, BPA Exh. 68, Attch. 1, p. 1).

The DSI's further suggest that by relying solely on information from Idaho Power Company, BPA has overestimated FY 1983 exchange costs for that company (DSI, Opening Brief, p. 4). They make the same argument for BPA's reliance solely on data provided by Portland General Electric Company. The DSI's cite a comment in support of such an argument made by Marcus Wood, an attorney for the ICP, that an exchanging utility is "very reluctant" to admit to BPA that its rates will be less than the maximum it is requesting before the state commission. Such an "admission" would create problems for the utility in its rate case proceedings (TR 5628).

However, I reject the suggestion that BPA should attempt to presume what the PUC's in the region would conclude in their rate proceedings. BPA has had very little experience in projecting the Average System Cost of these exchanging utilities. I believe that these utilities are in a far better position than BPA to esimate their own costs and loads. Furthermore, I do not believe that their optimism in these projections is unwarranted. As Mr. Wood points out for Pacific Power and Light, projections are made knowing in some years they may slightly overstate their requirements, and some years slightly understate (TR 5629).

I recognize the problems created for a utility in projecting its Average System Cost, I also believe that the intent of Pacific Power and Light, as revealed by Mr. Wood's statement is the common intent of all the exchanging utilities who were asked to project their Average System Cost. There is strong pressure on such utilities to be optimistic, in view of their regulatiory processes, with respect to their exchange cost estimates. I recognize that the ASC projections made by the exchanging utilities are only as accurate as their estimates of costs and loads.

The total exchange cost estimate is a composite of the individual estimates of nine companies. The DSI's object to estimates made by Portland General Electric Company and Idaho Power Company as being too high. They do not acknowledge that estimates made by other utilities may understate their requirements. I recognize that this may be the case, and I find that in the calculation of the overall costs of the exchange, there is a strong likelihood that the net effect of over or underestimates of the exchange may be balanced out to produce a reasonable estimate of FY 1983 exchange costs. I therefore cannot accept the DSI recommendation to make a downward adjustment to projected ASC's of Portland General Electric and Idaho Power companies.

The DSI's further suggest that the cities of Du Bois and Soda Springs, Idaho will not exchange in 1983 (DSI, Opening Brief, p. 10). The City of Du Bois, Idaho has voted not to participate in the exchange, and therefore, I agree that costs of their exchange should be eliminated from BPA's estimate. The City of Soda Springs, Idaho and BPA are currently in the process of determining whether that city can exchange, and I believe it prudent to assume that Soda Springs will exchange in FY 1983.

The adjustments that I have thus far indicated will reduce BPA's exchange cost estimate by approximately $28 million from that proposed in BPA's rebuttal testimony. I feel that the resulting estimate is reasonable, and that further reductions would be imprudent from the standpoint of BPA's ability to recover the costs of the exchange. However, because the evidence in the record indicates utilities rarely obtain all the rate relief they ask for, I have adopted an exchange cost adjustment to deal specifically with any inaccuracies in projected exchange costs. I will address this adjustment relative to my decisions in the Wholesale Power Rate Design Study.

VII. 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, the costs associated with each customer class as identified by the Cost of Service Analysis (COSA) are modified to account for the fact that revenues from certain rate classes (such as fixed contracts) will not necessarily equal the allocated costs. The allocated costs are further modified in this study to incorporate the rate design adjustments specified in the Regional Act. The methodology for some of the adjustments is strongly influenced by the results of the Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis.

The wholesale power rate proposal includes the following rate schedules:

1. Priority Firm Power Rate Schedule, PF-2.
2. Industrial Firm Power Rate Schedule, IP-2 (MP-2).
3. Special Industrial Power Rate Schedule, SI-2
4. Firm Capacity Rate Schedule, CF-2.
5. Emergency Capacity Rate Schedule, CE-2.
6. Firm Energy Rate Schedule, FE-2.
7. New Resource Firm Power Rate Schedule, NR-2.
8. Surplus Firm Power Rate Schedule, SP-1.
9. Surplus Firm Energy Rate Schedule, SE-1.
10. Nonfirm Energy Rate Schedule, NF-2.
11. Energy Broker Rate Schedule, EB-1.
12. Reserve Power Rate Schedule, RP-2.

Of these 12 schedules, 9 are based on previous BPA wholesale power rates. The remaining 3 schedules are based on new marketing concepts.

The process of electric utility ratemaking involves consideration of a number of rate design objectives. While BPA, as a Federal power marketing agency, is a nonprofit organization, its rate design objectives are similar to those of investor-owned or consumer-owned utilities. The basic objectives BPA follows in designing its wholesale power rates include:

(1) ensuring adequate revenues to meet its repayment obligation;

(2) distributing the revenue requirement in an equitable manner among recipients of the service by reflecting costs incurred and benefits received;

(3) designing rates to encourage conservation and minimize environmental impacts; and

(4) designing rates to encourage efficient use of resources including the Federal Columbia River Power System (FCRPS).

In addition, rate continuity, ease of administration, revenue stability, and ease of understanding also are considered in the rate design process.

B. Adjustments

In developing individual rate schedules, BPA adjusted the COSA results based on the findings of other studies and the rate design objectives. The adjustments are:

1. Excess Revenues
2. Fixed Contract Deficiencies
3. Value of Reserves
4. Low Density Discount
5. Hanna Adjustment
6. Displacement
7. Equalization of Demand
8. Exchange Adjustment Clause

Issues related to each of these adjustments are described in the subsections that follow.

1. Excess Revenues

During FY 1983, approximately $204.6 million in revenue from three sources will be produced in excess of allocated costs. The first source, the nonfirm energy rate (NF-2), will produce $173.2 million and is credited to FBS, new resources and transmission costs. The second source, the assignment of costs to the DSI top quartile, will produce $26.7 million and is credited to FBS and new resources costs. The third source, totalling $4.6 million, is from the assignment of costs to displaced new resources load served with Federal nonfirm energy and is credited to FBS and transmission costs. A summary of the components of the excess revenue adjustment can be found in Table 9 of the WPRDS.

In the initial proposal BPA allocated revenues from the generation component of the NF-2 rate to the FBS and new resources based on the total cost (excluding the Supply System) in each pool multiplied by the energy associated with each resource pool. The public agency representatives generally supported BPA's method or suggested that the revenue be allocated based on loads (Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-15, p. 48). ICP witness Deesen offered an alternative which allocates the generation portion of the revenue from the standard rate to the resource pools based on the total costs in that pool. Further, he proposed that the generation portion of the spill rate and nonfirm sales made in connection with the capacity/energy exchange be allocated solely to the FBS (Deesen, ICP, Exh. IO-14).

I agree that the ICP method is cost based and better tracks the rationale behind the NF-2 rate schedule than did the method used in the initial proposal. BPA staff and the WPUD's asserted that the Deesen method fails to recognize that the primary reason for nonfirm sales is the variability in streamflows. The majority of nonfirm sales are made at the spill rate, and the Deesen method allocates all these sales to the FBS. Therefore, I find that this method appropriately recognizes the FBS as the primary source of nonfirm revenue. Thus, in developing this final rate proposal, I have allocated the generation portion of nonfirm sales at the standard rate according to the total costs in the FBS and new resources pools.

The PPC criticized the method used in the initial proposal to determine the transmission portion of nonfirm revenues, asserting that the percentage split in the standard rate should be applied to the average rate (O'Meara, PPC, Exh. PB-11, pp. 10-11). The PPC method ignores the fact that the NF rate is lowered during spill conditions because of an abundance of generation availability. As the PPC's witness pointed out, the value of the intertie actually increases during spill conditions (O'Meara, PPC, Exh. PB-11, p. 11-12). Therefore, I have continued to use the average cost of the Federal Columbia River Transmission System (FCRTS) as the transmission component of the nonfirm rate.

BPA's classification of excess revenues was criticized and it was suggested that they be classified 100 percent to energy because they result from energy sales (Shanker, APAC, Exh. PA-1 p. 34). The PGP also criticized the method and advocated using the baseload hydro classification (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, p. 57). The ICP and WPUD's supported BPA's use of the reverse TDLRIC classification percentages (Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-7, p. 48; Shue, PPL, Exh. IO-29, p. 11).

I do not agree that either of the embedded cost methods for classifying the credit should be used, because they fail to recognize the current economic tradeoff between capacity and energy and would result in rates giving a less accurate price signal. I do agree that it is inappropriate to use the reverse TDLRIC percentages for the new resources portion of the credit because those resources were classified according to the TDLRIC percentages in the COSA. Therefore, I have classified the FBS portion of the credit according to the reverse TDLRIC percentages (83 percent capacity, 17 percent energy) and the new resources portion according to the straight percentages (17 percent capacity, 83 percent energy).

2. Fixed Contracts Deficiencies

BPA provides services to certain customers at contract rates that are not subject to change. The two categories of these fixed rate contracts are Canadian Treaty and capacity/energy exchange. These services are part of contractual arrangements that enable BPA to provide power that otherwise would be lost. The costs allocated to these services exceed the corresponding revenues. Therefore, BPA apportions these revenue deficiencies, as adjusted for excess revenues from sales of nonfirm energy, to the classes of service for which rates can be changed and for which the benefits of the added capacity and energy are received.

The Canadian Treaty results in an increase in the firm capacity and energy capability of the FBS, and power sales customers served by FBS resources benefit from this increased capability. Therefore the revenue deficiency associated with the Canadian Treaty fixed contracts is assigned to the users of the FBS. This deficiency is functionalized to generation and classified to both capacity and energy in the same manner as baseload hydro plants. The revenue deficiency is apportioned to rate periods on a pro rata basis relative to the billing determinants in each period and then allocated to classes of service on the basis of appropriate allocation factors. This process results in allocation of a portion of the Canadian Treaty revenue deficiencies to all capacity and energy sales customers served by FBS resources.

Under capacity/energy exchange contracts BPA is obligated to generate capacity when requested by a contracting customer. In turn, the customer is obligated to return the energy associated with the delivered capacity plus additional energy as payment for the capacity. When BPA does not require the return of the energy (for example, under high streamflow conditions), the customers are allowed to pay for their obligation in cash. In an average water year customers will pay in cash for a portion of their obligation to return energy to BPA. The energy returned is included as an FBS resource and revenues from energy not returned are credited to the FBS. Therefore, the capacity costs allocated to capacity/energy exchange are assigned to FBS users. Because energy customers receive the benefits of the firm power resources provided by these contracts, the capacity/energy exchange revenue deficiency is classified to energy (Table 11, WPRDS). The deficiency is prorated to rate periods on the basis of the FBS energy allocation factors (Table 12, WPRDS).

APAC suggested that, rather than allocating the deficiencies to particular classes of service, BPA should allocate the revenue deficiencies of these fixed contracts uniformly across all cost classifications as is done with the deferral (Cook, APAC, Exh. PA-2, p. 41). I disagree because the benefits from the Canadian Treaty and capacity/energy exchange are directly conferred on the users of the FBS resources (TR. 1959). In contrast, the revenue deficiency of the deferral cannot be attributed to any particular group and is, therefore, assigned to all customer classes.

The direct benefits to the FBS resources of the fixed contracts are: (1) the increased firm capacity and energy capability as a result of the Canadian Treaty contracts and (2) increased energy of the FBS as the result of the capacity/energy exchange contracts. If I were to allocate the costs of these fixed contracts to the holders of the contracts, rather than allocating the costs to the users of the FBS, I would be denying the contract holders the benefit of their contract.

3. Value of Reserves

BPA credits the DSI's for the value of reserves provided by the restriction rights in their contracts. The calculation of the value of the reserves and the amount of the credit is discussed in Section VII(C)(2)(d). The value of reserves credit results in a revenue deficiency that must be classified and allocated to the rate classes.

In the initial proposal the revenue deficiency was classified according to the fixed TDLRIC percentages. Various embedded cost methods for classifying the deficiency were proposed including classifying based on the overall COSA classification (Garman, Opatrny, Knitter and Sunday, PGP, Exh. PB-20, p. 58), classifying 100 percent to capacity (Cook, APAC, Exh. PA-2, pp. 42-43) and classifying based on the classification of a combustion turbine (Peseau, DSI, Exh. DS-3, p.30). As with the crediting of excess revenues, I believe it is appropriate to reflect the classification percentages in the TDLRIC Analysis. Consistent with the change in application of TDLRIC to thermal plant classification, the overall percentages rather than just the fixed cost percentages have been used.

The DSI's argue that no reserve costs should be allocated to loads served by exchange resources nor should any be allocated to the quartiles providing the reserves (Peseau, DSI, Exh. DS-3, pp. 30-32). However, as the WPUD's pointed out, the Federal system reserves are provided for three quartiles of DSI load (Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-31, p. 5). Therefore, it is appropriate to allocate the deficiency caused by the value of reserve credit to all firm loads.

4. Low Density Discount (LDD)

A low density discount is included in the PF-2 priority firm power rate schedule. The 3, 5, or 7 percent discount is applied to the monthly charges for priority firm power. The revenue deficiency that results from granting the discount is first classified to capacity and energy according to the classification of all priority firm costs and then allocated to the priority firm customer class.

A suggested alternative was to classify the LDD to capacity only, because the LDD is related to fixed dispersal costs (Cook, APAC, Exh. PA-2, p. 43). While I agree that most of the costs related to dispersed systems are fixed costs, I do not agree that the LDD should result in a change in priority firm classification percentages. Since the LDD is applied to both the capacity and energy charges uniformly, the deficiency should be classified similarly. Classification of the LDD deficiency to capacity would have the result of moving away from cost-based rates, average embedded cost rates as well as incremental cost-based rates.

PNGC suggested that the cost of the LDD be allocated to all customers as is the Hanna discount (Jones, PNGC, Exh. PB-22, p. 7). The Hanna discount is based on Hanna's use of raw materials indigenous to the region. Since the Hanna discount is justified on the basis of regional and national benefits, the cost was allocated to all BPA customers. The only beneficiaries of the LDD, on the other hand, are priority firm customers. Therefore, I believe it is appropriate to allocate the LDD costs exclusively to that customer class.

It also was suggested that any revenue deficiency from granting an LDD for exchange purchases should be allocated as exchange costs (Jones, PNGC, Exh. PB-22, p. 6). This suggestion confuses loads and resources. The LDD is a discount applied at the load level and does not affect the costs associated with the exchange resources. Since residential and small farm customers of exchanging utilities are priority firm loads, the costs of an LDD granted to them should be allocated to priority firm customers.

5. Hanna

The establishment of a special rate for Hanna results in a revenue underrecovery which has been allocated to all customers. The adjustment is much smaller than the adjustment in the initial proposal because even though the Hanna rate is higher (see Section VII(C)(3)), the forecast load (1.6 average megawatts) is much lower.

APAC and PPC object to the method of allocating the costs associated with the Hanna adjustment (Cook, APAC, Exh. PA-2, p. 43; Wolverton, PPC, Exh. PB-9, p. 3; Wolverton, PPC, TR. 2445). They contend that the reasoning and allocation of the Hanna adjustment should be consistent with the low density discount, as both provisions result from the Regional Act and are designed to benefit a particular class. Therefore, they proposed that the Hanna adjustment be borne by the DSI class.

A review of the record and statutory provisions, however, indicates that the low density discount and the Hanna adjustment are two separate and unrelated issues. This is further supported in that Section 7(d)(2) addresses establishment of an entire rate for a customer while Section 7(d)(1) addresses a discount to the rates of many customers. Also, the legislative history suggests that Section 7(d)(2) was designed specifically for Hanna and is based, in part, on considerations of Hanna's national strategic importance (Hanna Reply Brief, pp. 2-3). Having a domestic source of a strategic metal is of value to the nation. The regional economic and social considerations associated with Hanna are vastly different than the impact of the low density discount on the retail rates of BPA's customers with low system densities. This distinguishes the special rate for Hanna from the LDD and justifies sharing the cost of the Hanna adjustment among a broad base of customers. For these reasons I believe the Hanna adjustment should be allocated to all customers.

6. Displacement

For the final proposal, based on the assumption of average water conditions in FY 1983, I am assuming for rate purposes that Weyerhaeuser/Longview Fibre (W&LF) and Centralia will be displaced during portions of the year by nonfirm energy. Since displacement of these resources lowers the amount of nonfirm available for sale, it is appropriate to assign the opportunity cost of those lost nonfirm sales to the users of those resources. The opportunity cost of the lost sales is equal to the average nonfirm rate. If the average nonfirm rate were assigned to the users of displaced resources, the new resources portion of the average nonfirm rate would be credited to these same customers since both displaceable resources (W&LF) are new resources. Therefore as a simplifying step, only the FBS and transmission portions of the average NF-2 rate are assigned to the displaced resources.

This procedure is the same as that used in the initial proposal (which was noncontroversial during the hearings) except that in the initial proposal the transmission portion of the average NF-2 rate was excluded from both the opportunity cost calculation for displacement and the pricing of the DSI top quartile. Upon reexamination of the logic of this step, I found that this treatment was appropriate for the top quartile because transmission costs are allocated to the top quartile, but inappropriate for displacement which results in a reduction in total sales. Therefore, for the final proposal I have included the transmission portion of the average NF-2 rate in the calculation of the opportunity cost of displacement.

7. Equalization of Demand

In the initial proposal the PF-2 and CF-2 annual capacity rates were equalized. The IP-2 (MP-2), NR-2, and SP-1 capacity rates were then set at the same level as the equalized PF-2 and CF-2 rates by moving capacity dollars to the energy charge. In the final rate proposal the same general principle has been applied, but the seasonal CF-2 rate has been equalized as well.

APAC and the ICP criticized the equalization process, claiming that equalization defeats the purpose of performing a cost of service study and causes firm capacity purchasers to pay significantly more than PF-2 customers relative to their contribution to BPA's costs (Cook, APAC, Exh. PA-2, p. 45; Shue, ICP, Exh. IO-17, pp. 12-14). I believe that the equalization process is fair. Firm capacity customers are treated as if they were part of the 7(b) pool for rate design purposes. It is not unusual for a subset of a rate class to pay more (because of noncoincidental demand billing determinants) than they would have if they were treated as a separate customer class. This is true of any subclass that has a lower coincidence factor than the class as a whole. This treatment of the CF customers results in a considerably lower rate than if they were treated as 7(f) customers. The ICP noted that the equalization step was applied to annual but not seasonal capacity customers (Shue, ICP, Exh. IO-17, pp. 12-14). I agree that there was no rationale for this differentiation and have therefore equalized the seasonal CF-2 demand charge (excluding that portion of the charge attributable to the intertie because only seasonal capacity customers use the intertie).

In rebuttal testimony BPA suggested that it may be inappropriate to equalize the IP-2 demand charge because equalization reduces the contract curtailment charges (Metcalf, BPA, Exh. BPA-69, pp. 6-7). I have decided that, although I am concerned about revenue stability from the IP class, it may be inequitable at this time to single out this class for special treatment.

Section 7(e) of the Regional Act allows BPA to equalize demand charges. I have exercised this option in order to facilitate administration of the rates and insure that no customer has the incentive to purchase capacity and thereby avoid a higher capacity charge in a power rate. This adjustment does not affect the revenue requirement of the rate pools.

8. Exchange Adjustment Clause

An exchange adjustment clause was included in the initial proposal. This adjustment clause would have allowed BPA to collect any increase in exchange costs caused by an underestimation of the average cost of the exchange or the amount of the exchange loads. The adjustment clause, as initially proposed, applied only to underrecoveries of exchange costs; that is, the rates would not adjust downward if there was an overrecovery.

Virtually all parties who commented on the adjustment clause opposed it. The DSI's asserted that the variability of exchange costs was no greater than other costs (Drazen and Schoenbeck, DSI, Exh. DS-5, p. 31). The ICP and the PPC pointed out possible administrative burdens which an exchange adjustment clause would cause (Drazen and Schoenbeck, DSI, Exh. IO-14, pp. 12-13; TR. 2450). BPA staff noted the adjustment clause might hamper the marketability of the surplus resources (Staff Eval., p. 70).

The PPC, DSI's and BPA staff all agreed that the adjustment clause if adopted should be adjustable downward. The DSI's have asserted that BPA's forecast of the cost of exchange resources is too high, because the forecasts provided by the IOU's were accepted uncritically and those estimates are biased upward because of the state regulatory process (Schoenbeck, DSI, Exh. DS-10, p. 1).

Based on this record, I have substantially modified the exchange adjustment clause in the final rates. It is the nature of forecasts to be too high or too low, so I am not prepared to revise the estimate of exchange resource costs downward solely based on the DSI testimony. Even if the individual changes advocated by the DSI's are essentially correct, there may be offsetting underestimation of other utility's average system costs (ASC's). However, I have adopted an exchange adjustment to deal specifically with the problem raised by the DSI's.

The adjustment is in the form of a rebate if the actual average cost of the exchange for FY 1983 is less than forecast. No surcharge will be assessed if the average cost of the exchange exceeds the forecast nor is there an explicit adjustment for differences in the total exchange load. (Of course, changes in the relative mix of the exchange load between exchanging utilities will affect the average cost of the exchange.) For each rate schedule served with exchange resources, the rebate will be the product with interest of: (1) the percentage of that class's revenue requirement which was composed of exchange costs; (2) the percentage overestimation of exchange costs; and (3) the customer's total FY 1983 bill under the rate schedule. To avoid the administrative costs and problems associated with rebating small sums of money, rebates will be paid only if the product of (1) and (2) is greater than 0.1 percent. The rebate will be paid after October 1, 1983, and reviewed and adjusted once after October 1, 1984, to incorporate any corrections in exchanging utilities' FY 1983 ASC's or exchange load.

I believe that the form of the exchange adjustment in the final proposal meets the objections of the parties to the adjustment clause in the initial proposal while handling the possible overestimation of the cost of exchange resources.

C. Rate Schedules

In this section the proposed rates and related issues are discussed.

1. Priority Firm Power Rate Schedule, PF-2

a. Description of the Rate

The PF-2 rate schedule is for sale of firm power to be used within the Pacific Northwest by public bodies, cooperatives, Federal agencies, and utilities participating in the exchange under Section 5(c) of the Regional Act.

The rate consists of a demand charge which is time-differentiated on both a seasonal and diurnal basis, and an energy charge that is seasonally differentiated only. Additional charges may be imposed for either a leading or lagging power factor or for an unauthorized increase. There is no transformation charge or special provision in this rate for at-site power, but a low density discount is available to qualifying utilities.

b. Tiered Rates

In its initial proposal BPA chose not to propose a tiered rate structure for its Priority Firm power rate schedule. A number of tiered rate issues were discussed in Appendix B of the Wholesale Power Rate Design Study prepared for the initial proposal.

The PPC, WPUD's, and APAC opposed the use of tiered rates by BPA for several reasons. First, concern was expressed about the effectiveness of a tiered rate at the wholesale level in encouraging efficient electricity use (Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-15, pp. 45-46; Shanker, APAC, Exh. PA-1, p. 37; and Wolverton, PPC, Exhibit PB-15, p.5). Second, tiered rates were thought to be potentially inequitable, specifically with regard to the effect on nongenerating utilities and energy intensive industries (Baxendale, PPC, TR. 4431-4; Wolverton, PPC, Exh. PB-9, pp. 5-6; Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-15, pp. 47; Shanker, APAC, Exh. PA-1, p. 37). Third, tiered rates were viewed as a threat to BPA's revenue stability (Saleba, Russell, Schneider and Hutchison, WPUD, Exh. PB-15, p. 46; Shanker, APAC, Exh. PA-1, p. 37; Wolverton, PPC, Exh. PB-9, p. 6). Finally, it was suggested that no adequate method of assigning a base allocation on which to structure a tiered rate had been developed (Wolverton, PPC, Exh. PB-9, p. 6).

People's Organization for Washington Energy Resources (POWER) supported implementation of a tiered Priority Firm power rate by BPA (Powers, POWER, Exh. WO-1). POWER stated that tiered rates would improve the accuracy of price signals, encourage a more efficient use of electricity, and enhance BPA's revenue stability by assuring that revenues would parallel costs more closely. POWER also suggested that tiered rates would provide a more equitable reward to conserving consumers and should be recognized as a primary means of encouraging energy conservation, possibly supplemented, although not replaced, by billing credits.

I have decided not to tier the Priority Firm power rate for several reasons. First, I am concerned about the potential adverse effect of a tiered rate structure on BPA's revenue stability. A large portion of BPA's costs are fixed and do not vary as load varies. Also, I am concerned that a tiered Priority Firm rate may introduce inequities into the sale of priority firm power and could create serious cash flow problems for customers. In addition, in light of BPA's responsibility to provide billing credits for conservation and consumer-owned renewable resources, as required by the Regional Act, I am concerned that a tiered rate imposed for the purpose of discouraging consumption of electricity may be unwarranted. Finally, tiering the Priority Firm rate would significantly increase BPA's administrative responsibilitites.

c. Low Density Discount (LDD)

A low density discount (LDD) was included in the PF-1 Priority Firm Power rate schedule pursuant to Section 7(d)(1) of the Regional Act. This discount was instituted to avoid adverse impacts on retail rates of utilities with low system densities. All customers purchasing priority firm power, both public and investor-owned, are eligible for the discount provided their systems meet the system density criteria established by BPA.

The amount of the discount will be a function of either (1) the ratio of the purchaser's preceding calendar year total electrical energy requirements to the purchaser's depreciated investment in electric plant in service (excluding generating plant) on December 31 of that year, or (2) the purchaser's ratio of residential consumers to the number of pole miles of distribution line. The first ratio is a measure of investment in distribution plant and the second is a measure of physical system density. The discount will be computed both ways and the utility will be awarded the higher of the two possible discounts unless it has more than 10 residential consumers per mile of distribution line. In that case the customer is not eligible for any discount, regardless of the investment ratio. The customers entitled to a discount are listed in Table 15 of the WPRDS.

BPA included a LDD in the initial proposal. The discount was basically the same as last year's, although two changes were made: (1) circuit miles were used in the calculation of the physical system density ratio, and (2) the discount for customers who serve areas both inside and outside the region was based only on that portion of their service area which is in the region.

The PNGC contended that pole miles, not circuit miles, should be used as a measurement of physical system density (Jones, PNGC, Exh. PB-22, pp. 7-9). I agree with this comment since pole miles better describe the geographic distribution of a utility's consumers, and the utility's investment in distribution plant has already been measured by the other ratio (the proportion of investment in plant relative to energy sales).

The PNGC also argued that it is inconsistent and inappropriate to segment a system by regional boundaries when determining whether a customer actually has a low system density (Jones, PNGC, Exh. PB-22, p. 6). I believe that it is appropriate to consider that portion of a customer's service area within the BPA region rather than the customer's entire service area when determining eligibility for the discount. By so doing, I am making the benefit of the LDD available to all consumers in the BPA region served by customers with low system densities. This change is only expected to affect Utah Power and Light.

The PNGC argued that the beneficiaries of the LDD should be systems such as rural electric cooperatives with high distribution costs due to difficult terrain, and remote and sparsely populated service areas (Jones, PNGC, Exh. PB-22, p. 3). I believe that all customers that would qualify for the LDD under the criteria described above are systems such as rural electric cooperatives with high distribution costs, so the proposed criteria remain appropriate. In addition, the PNGC stated that the 1981 LDD formula, which is identical to the 1982 formula, provided benefits to systems with high distribution costs such as small electric cooperatives (Jones, PNGC, Exh. PB-22, pp.1-2). It follows, therefore, that the 1982 formula is equally appropriate.

The PNGC also suggested that the LDD formula is fixed in section 8(g) of Exhibit A to the Power Sales Contract for a 5 year period (Jones, PNGC, PB-22, p. 4). I believe that the plain language of the contract provides that the LDD is subject to adjustment in each BPA rate adjustment process. The suggestion that the LDD would be subject to review but would not be subject to change does not make sense (Jones, PNGC, TR. 3661).

POWER suggested an alternative LDD design. The discount to each qualifying utility would be based on the number of customers served rather than a uniform discount off their power bill. It was asserted that this design would encourage conservation and would provide a better equalization of retail rates by offsetting high distribution costs (Lazar, POWER, Exh. WO-4, pp. 17-20).

POWER suggests that the LDD formula proposed by BPA does not achieve the intent of compensating utilities for high distribution costs (Lazar, POWER, Exh. WO-4, p. 3). The language of section 7(d)(1) of the Regional Act does not mention distribution costs. While the legislative history of the Act mentions high distribution costs, it does so in describing the nature of low density systems and not in providing a sole basis for establishment of the LDD formula.

POWER and the OPUC were concerned that the LDD promotes energy consumption (Girard, Taussig and White, OPUC, Exh. SC-1, p. 10; Lazar, POWER, Exh. WO-4, p. 4). I do not believe that the LDD has this effect. While the discount was suggested as providing a disincentive to conserve energy, testimony also noted that the LDD would result in higher rates to customers who are allocated LDD costs but are not eligible for the benefits. This fact, by the same rationale, would create an incentive for conservation. The conflicting nature of the testimony regarding the LDD's effect on conservation does not provide a reason for altering the LDD formula.

The OPUC suggested that the apparent basis for granting the LDD is that utilities with sparsely settled service territories have higher rates, which is not necessarily the case (Girard, Taussig and White, OPUC, Exh. SC-1, p. 10). OPUC failed to cite any legislative history supporting their assumed rationale. To the contrary, the basis for granting the LDD is to avoid adverse impacts on retail rates of the Administrator's customers with low system densities.

d. Unauthorized Increase

When either a computed demand or contract demand customer takes more Federal firm power than permitted under the terms of its contract, the Administrator may charge for that overrun or unauthorized increase.

In the initial proposal a rate of 130 mills per kilowatthour was proposed for energy taken as unauthorized increase. The rate for unauthorized increase is a charge for power which the customer has taken either without a contract or outside of the terms of a contract. The charge must be set high enough to discourage a customer from intentionally taking power from BPA during a shortage rather than buying power from other available sources. By taking an unauthorized increase, power customers are jeopardizing the integrity of the generation control system. For that reason, a charge is necessary.

The PGP indicated that it supported development of a cost-based rate for unauthorized increase (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, pp. 43-45). I concur with that suggestion and am now basing the charge on the incremental fuel costs of operating an oil-fired combustion turbine. By using a resource with a very high operating cost as the basis of the charge, I can be sure that BPA recovers any potential expense associated with providing an unauthorized increase.

The PGP also commented that charges for unauthorized increases could be handled more equitably as a contract matter than as a rate issue (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, p. 43). The new power sales contracts include a "Relief from Overrun Exhibit" which details when the unauthorized increase charge will apply. I believe that, while the contract should state when the charge will be imposed, the actual rate should be included in the rate schedules. Otherwise, it would be more difficult to change the rate as the costs of providing the service change.

e. Transformation Charge

In 1979 the Administrator determined that it was inappropriate to develop a separate charge for lower voltage delivery facilities. The reasoning behind his decision remains valid today. Although the PGP argued that BPA's rates are supposed to be cost-based, and that provision of transformation services constitutes a cost to BPA (Garman, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, pp. 51-55), it does not follow that BPA should separately charge for that cost. If I were to pursue that line of reasoning, separate charges for transmission distance, location and age of facilities also would have to be included in the rates.

It has been further argued that utilities have made long-range financial commitments because of the transformation charge which was in effect during the 1974-1979 rate period (Garman, Opatrny, Knitter, Sunday, and Long, PGP, Exh. PB-20, pp. 51-55). However, BPA has already indicated (1981 Administrator's Record of Decision, p. IX-14) that "BPA will mitigate any net adverse impacts that can be substantiated." BPA will attempt to alleviate any hardships resulting from the rejection of the transformation charge and will continue to consider specific requests from customers who believe they were financially harmed by the 1979 change in rate structure.

For the 1982 Wholesale Power Rate Proposal, I am combining delivery facility costs with other demand costs so that these costs can be distributed among all firm power customers through an equalized demand charge as permitted by Section 7(e) of the Regional Act. There is insufficient evidence on the record to support adoption of a separate charge for transformation. However, the recent Exchange Transmission Credit Agreement provides transmission benefits to public agencies who would be eligible to exchange with BPA under the Residential Exchange Contract.

Because public agencies with existing low cost generating resources receive no corresponding benefits for their transmission systems, I have agreed to re-examine the merits of a transformation charge in BPA's next wholesale rate proposal.

2. Industrial Firm and Modified Firm Power Rate, IP-2 (MP-2)

a. Description

The IP-2 (MP-2) rate schedule is for sales of Federal power to BPA's direct-service industrial (DSI) customers, and replaces schedules IP-1 and MP-1. The loads of the DSI's differ from typical utility loads in that they can be restricted by BPA for various reasons and in various amounts. This feature increases the reliability of service to firm customers' loads when the Federal system is unable to meet its firm power commitments. Because at least one DSI still could revert to a Modified Firm contract which would provide BPA with significantly less restriction rights, no value of reserves adjustment will be made for sales under Modified Firm power sales contracts. All other terms of sale for the IP-2 and MP-2 customers are the same. The demand charges are time differentiated on both a daily and a seasonal basis. The energy charge is seasonally differentiated based on an analysis of the cost of seasonal hydro storage. The IP-2 (MP-2) rate includes an exchange adjustment and a power factor penalty, but the minimum bill provision in the initial proposal has been deleted from the final.

b. Minimum Bill

In the initial proposal the IP-2 (MP-2) rate schedule included a minimum bill. The monthly minimum bill was equal to the annual revenues BPA would collect from the lower three quartiles of the customer's load divided by 12 months. The minimum bill was proposed to insure that BPA would collect at least a portion of the revenues forecast to be received from the DSI's.

The DSI's criticized the proposed minimum bill, suggesting it does not recognize the seasonal variation in the IP-2 rates; it fails to recognize that curtailed power could be sold and the effect of DSI curtailment mitigated; it represents a return to a pure capacity rate; and it imposes an additional charge on top of the contractually imposed curtailment charge. The DSI's also stated that a minimum bill creates inequities between the customer classes and between the individual industries, and argued that applying the minimum bill only to the DSI's is discriminatory. They criticized BPA's forecast of their DSI load, and suggested that adoption of a more realistic, lower load forecast would obviate the need for a minimum bill (DSI Opening Brief, pp. 15-19).

On the other hand, the PPC and ICP criticized the minimum bill because a large revenue deficiency could develop before the proposed minimum bill takes effect. They stated that this problem is exacerbated by the melding of the lower priced top quartile with the higher priced lower three quartiles. Alternatives or supplements to the minimum bill were offered including a two-part rate, a customer charge, or a minimum bill with mitigation at the nonfirm rate (which is, in essence, a customer charge) (Wolverton, PPC, Exh. PB-9, pp. 9-10 and TR. 2446; Shue, ICP, Exh. IO-17, pp. 17-18; Lauckhart, ICP, TR. 3691; Metcalf, BPA, Exh. BPA-69, p. 3).

The DSI's posed many of the same objections to these alternatives as to the minimum bill. They stated that these alternatives would change, in a fundamental way, the relationship between BPA and the DSI's, and objected to doing so in a rate filing (Drazen and Schoenbeck, DSI, Exh. DS-5, pp. 35-37). Based on this record I have decided not to incorporate a minimum bill, customer charge, or blocked rate in the final IP-2 rate. As the DSI's suggested, I have used a lower forecast of the DSI load. By forecasting 50 percent service to the top quartile, the risk of underrecovery caused by top quartile curtailments is balanced by the possibility of overrecovery if service is greater than forecasted.

I continue to believe that revenue stability is an important objective, and that revenues from the IP class are less stable and predictable than from the PF class because of the high fixed cost resources used to serve the load, the homogeneity of the load, and the melding of costs from the top quartile with those of the lower three quartiles. Nevertheless, the record shows that BPA and the parties had considerable difficulty finding an alternative which was equitable to the DSI's as a class and to individual DSI's. Incorporating additional features, such as mitigation by sale of curtailed power, annual revenues from individual customers, monthly and annual revenues from the IP class, operating conditions, and the DSI's contractual right to curtail the second quartile while the top quartile is being served with energy shifted in time, creates a complicated and unwieldy rate.

The DSI's objected to the presentation of alternative aproaches to the minimum bill in BPA's rebuttal case. It must be noted, however, that in customer meetings prior to the rate case, the DSI's indicated that a minimum bill was a preferable means to assure collection of forecasted revenues from DSI's rather than a number of other alternatives. After the minumum bill was presented in BPA's initial proposal, however, the DSI's responded in their direct case only with criticism and with no suggestions whatsoever of alternative methodologies. As the record in this case demonstrates, the DSI's have engaged in substantial curtailments in recent years. Due to the resulting revenue shortfall BPA had to consider alternatives to insure revenue stability. I believe it appropriate that when parties raise objections but offer no alternatives, rebuttal is the appropriate phase of the hearings where other parties may raise alternatives. This is the process the BPA staff undertook in this rate case.

The DSI's have indicated a willingness to meet and discuss minimum bill and other rate alternatives for possible consideration in the 1983 rate case (letter from Jonathan A. Ater to Peter Johnson, dated July 14, 1982).

c. <u>Assigning Costs to the Top Quartile</u>

BPA does not plan resources to serve the top quartile on a firm basis, so no costs other than transmission are allocated to the top quartile in the COSA. The top quartile is served with a combination of energy shifted in time (shifted FELCC, advance energy, and flexibility) and nonfirm energy when it is available. In the initial rate proposal BPA used an opportunity cost concept to assign costs to top quartile service. That part of the top quartile served with shifted non-surplus FELCC was priced at the generation portion of the NF-2 standard rate, while the energy used to serve the remaining portion of the top quartile was priced at the generation portion of the average nonfirm energy rate. In the final rate proposal BPA will continue to use the opportunity cost concept to assign costs to the DSI top quartile service. The opportunity costs will be set at the generation portion of the average NF energy rate for each month. The portion of the top quartile served with shifted FELCC is assigned the generation portion of the NF-2 standard rate.

Both the DSI's and the PPC argued that the opportunity cost concept was being applied incorrectly. The DSI's claimed that all top quartile service should be priced at the nonfirm energy spill rate because of BPA's restriction rights. They also stated that since BPA could not sell the shifted FELCC on the same terms to other customers, it was not appropriate to consider the value of that service in determining the opportunity cost of the top quartile (Mizer, DSI, Exh. DS-2, pp. 11-15). The DSI's also disagreed in principle with the opportunity cost methodology and proposed using the average energy cost for all FBS resources (DSI Reply Brief, pp. 7-11).

The PPC, on the other hand, felt that BPA had erred by using the average yearly nonfirm energy rate to assign top quartile cost. They thought that it would be more appropriate to apply the monthly average nonfirm rate to the monthly DSI loads when determining the costs attributable to the DSI top quartile. The PPC further contended that use of the nonfirm rate might be understating the value of the energy because the DSI's are given priority over Southwest customers (O'Meara, PPC, Exh. PB-11, pp. 3-6).

The DSI's may argue that the opportunity cost pricing concept for DSI top quartile service is inconsistent with the formula contained in Appendix B of the Senate report on S. 885 (DSI Reply Brief, p. 8-9). They correctly point out that the algorithm contained in Appendix B priced the top quartile at the average energy cost of FBS hydro resources. I have consistently refused to apply the algorithm contained in Appendix B of the Senate report because I believe I have a statutory obligation to apply my understanding of the Regional Act to continuously changing circumstances. (For example, see my discussion regarding two versus three rate pools contained in Exhibit B hereto.) At the time the Senate report was prepared, the assumed average nonfirm energy rate was very close to the average FBS cost. Thus the "accounting cost" of the resource used to serve the top quartile was very close to the "opportunity cost." Today the DSI top quartile is served with a variety of resource uses that improves top quartile availability and creates a grade of power which varies in value and thus in opportunity cost. Because of the completely changed load and resource conditions which exist today from those estimated assumptions used in Senate Appendix B, I will continue to measure the quality of service afforded the top quartile in assigning costs to that service.

I agree with the PPC that the average nonfirm energy rate should be applied on a monthly, not a yearly basis. It would not be appropriate to price the entire top quartile at the spill rate since the grade of power and timing of service provided could command a greater price than does spill on the open market. Although it is true that BPA does not have the opportunity to sell top quartile energy to other customers on exactly the same terms, the opportunity cost concept does provide a good approximation of the cost of service to the top quartile. It should be noted that the techniques used to increase the firmness of the top quartile are completely voluntary. For that reason it is appropriate to consider the value of the shifted FELCC in assigning costs to the top quartile. On the other hand, I believe that those who think the DSI's should pay a premium because they are beneficiaries of the Northwest Preference Act are forgetting that no Northwest customer pays a premium for its regional preference status. Thus, it would not be reasonable or appropriate to impose such a charge only on the DSI's. Therefore, I have priced the shifted FELCC at the generation portion of the Standard Rate and all other top quartile service at the generation portion of the average nonfirm rate, calculated on a monthly basis.

The DSI contract requires that BPA use surplus FELCC, to the extent it is available, to serve the top quartile. BPA will give each industry the option to have its top quartile served with surplus FELCC or with the usual combination. Each industry will inform BPA, before the beginning of the fiscal year, the periods for which it wants service with surplus FELCC. During those periods the customer will be billed for its total load at the surplus FELCC rate, regardless of the size of its total load (even if it curtails the top quartile).

The rate for customers requesting top quartile service with surplus FELCC was designed by removing the costs assigned to the top quartile and dividing the remaining costs by the lower three quartile billing determinants. The result is the unit cost for firm service. This method should result in virtually the same rate as would assigning exchange resource and other costs to top quartile service. In addition, this method is simpler because no estimate is needed for the amount of surplus FELCC service taken.

BPA staff asserted that the surplus FELCC should be sold on a take-or-pay basis to assure recovery of the cost of those resources (Metcalf, BPA, Exh. BPA-69, p. 2). However, I have decided that it is inequitable to make the rate take-or-pay because: (1) in order to increase the marketability of SP-1 power, service under the SP-1 rate may not be take-or-pay; and (2) BPA is retaining its restriction rights.

The DSI's asserted that the value of reserves should be adjusted upward if firm resource costs are assigned to the top quartile (Mizer, DSI, Exh. DS-2, p. 7-9). I do not agree that an additional value of reserve credit should be developed because the DSI's retain the choice to receive nonfirm top quartile service. Also, BPA would undercollect if an additional credit were given and some firm service was taken because there would be no way to charge other customers for the credit.

d. Value of Reserves

BPA's firm power sales contracts with the DSI's provide the Federal system with reserves through the ability under certain conditions to restrict or interrupt portions of the industrial load. A value of reserves analysis was performed for the initial filing to measure the benefit resulting from the ability to restrict the DSI load and to comply with Section (7)(c)(3) of the Regional Act.

The Federal system reserves provided by the DSI restriction rights are separated into three parts: forced outage reserves, stability reserves and plant delay reserves. This separation follows the language and intent of Section (7) of the new DSI power sales contracts. Forced outage reserves (capacity and energy) maintain the operating integrity of the Federal system through the ability to restrict the DSI load. Stability reserves prevent regional and interregional instability resulting from underfrequency on the electrical grid through restricting the DSI load (Initial WPRDS, Exh. BPA-7, p. 21). Plant delay reserves protect the reliability of the system from construction delay and poor performance of existing plants through second quartile restriction rights.

To avoid double counting reserves, the quartiles were categorized based on the reserves they predominately provide (Jones, BPA, Exh. BPA-35, p. 6). Inherent in the pricing of the top quartile is the recognition of the available reserves associated with that quartile. That is, the application of the nonfirm rate in the pricing of the top quartile provides compensation for the reserves being provided (Jones, BPA, Exh. BPA-35, p. 6). The second, third, and fourth quartiles provide both stability and forced outage reserves. However, since the fourth quartile only can be restricted for 15 minutes at any one time, this quartile was not assigned a value for forced outage reserves. Thus, only the second and third quartiles were valued for forced outage reserves.

The reserves are valued according to expected use in conjunction with the provisions contained in the power sales contracts. Thus, a determination is needed of the reserve level in the test year, the amount of reserves provided through the restriction rights, and the expected use.

The PPC and ICP raised objections to the methodology and assumptions used in determining the amount of reserves needed on the system for the test year (Schultz, ICP, Exh. IO-13 p. 4-6; Russell, PPC, Exh. PB-7 p. 5). Specifically, the objections related to the use of 1979 Pacific Northwest Utilities Conference Committee (PNUCC) projected peak load data and inclusion of the top quartile of the DSI load in this data. Since ratemaking adjustments and assumptions should be based on the most current reliable data, I agree that basing the needed reserves on 1979 projected loads, including the top quartile, is not appropriate. For the final proposal, the 1982 load forecast is used because it more accurately reflects test year reserve requirements. Although the inclusion of the top quartile of the DSI load to determine reserve requirements is consistent with PNUCC planning procedure, I believe that the top quartile should not be included in the value of reserves analysis. This is consistent with the assumptions used for cost allocations in the COSA.

The ICP and PPC contend that the value of DSI restriction rights for forced outages is zero for FY 1983 (Schultz, ICP, Exh. IO-13; Russell, PPC, Exh. PB-7, p. 10) They assert that the projected surplus condition for FY 1983 reduces the need for these reserves. They also contend that numerous barriers and limitations existing in the contracts will constrict BPA's ability to use the restriction rights for reserves.

A surplus condition results because resources are greater than loads. There are various means available to return loads and resources to a balance. One alternative is to seek new markets for the surplus. It is my obligation to make every effort to market the surplus power. If DSI restriction rights did not provide the Federal system with reserves, there would be less surplus available to market, and therefore less revenue from surplus sales. The DSI's contend that BPA's customers gain more from sales of surplus resources than from BPA releasing restriction rights (Peseau, DSI, Exh. DS-7, p. 11).

Absent the restriction rights, BPA would have acquired standby generation to provide reserves. The costs associated with the standby generation would have been included in the Repayment Study as part of BPA's fiscal obligations. A surplus condition would not relieve BPA of this financial obligation. Furthermore, subjecting the value of the reserves to short-term fluctuations in loads and resources disregards the long-term contractual nature of the reserves (Peseau, DSI, Exh. DS-7, p. 11). BPA has the right to restrict or interrupt the DSI load on a long-term basis, thereby avoiding additional resource acquisitions for reserves. Since reserves provided by the DSI restriction rights are a part of BPA's long-term resource mix, the value of the reserves should not vary with the current load/resource balance.

Regarding the limitations resulting from contractual agreements, the ICP and PPC focused on three conditions of use that they assert decrease the value of forced outage reserves. The first contractual condition of service raised is that of Section 14(h)(3). The PPC and ICP argue that this section of the DSI contract renders the DSI restriction rights useless to meet BPA's Coordination Agreement obligations. The PPC and ICP interpret this section to mean that "DSI restriction rights can be used to meet obligations of coordinated utility systems only if BPA allows the DSI's to seek additional compensation from BPA if such use is made, and that the DSI's also have reserved the right to sue third party utilities for damages for use of the restriction rights to meet Coordination Agreement obligations." In effect, they argue that since the DSI's can demand compensation from BPA when restricted, the DSI's should not receive compensation in the form of value of reserves now (Schultz, ICP, Exh. IO-17, pp. 7-10). DSI counsel stated on the record that DSI reserves can be used to meet BPA's Coordination Agreement obligations to insure stability on any system associated with the Federal system (TR. 4195-97). DSI counsel stated in their reply brief that Section 14(h) of the DSI contract "does not impose any cost or liability on any party properly calling on the DSI reserves" (DSI Reply Brief, p. 41). My legal counsel advises me that the rights the DSI's reserved in Section 14(h)(3): ". . . does not make the third party utility strictly liable to the DSIs. Unless the utility's forced outage was the result of a wrongful act or omission on the part of the utility, the DSIs have no right to seek damages" (BPA Reply Brief, p. 36). Therefore, based on the advice of counsel and the statements of DSI counsel, I find that this section of the contract does not diminish the value of reserves.

The second contractual condition of service raised by the ICP and PPC is the provision that BPA must attempt to purchase energy prior to restricting the DSI second and third quartiles. They argue that this decreases the value of reserves, as the purchase would be made despite the restriction rights. The conclusion reached by these parties depends on two assumptions: (1) that energy is readily available at a reasonable price; and (2) that energy is readily available at the necessary time (TR. 2037). I believe that these assumptions are not reasonable for long-range planning purposes. Prudent utility planning does not operate on the premise that reserve margins can be planned or maintained based on assumed future purchases. Attempting to purchase prior to restriction does not guarantee purchase power will be available in sufficient or even significant quantities to meet unforeseen conditions. If purchases are not available, the DSI restriction rights can be used and these reserves provide predictability in terms of availability and quantity. The DSI restriction rights serve as reserves and, without reasonable assurance of the availability of purchase power, they should be valued assuming no purchase can be made. However, for the 1983 test year, written indications of cost and availability of purchase power were provided to BPA by utilities (Jones, BPA, Exh. BPA-35, p. 9). Based on those availability and cost projections, the impact of the contractual purchase requirement was factored into the value of reserve calculation. The difference in cost to BPA between purchasing to cover an outage instead of restricting and purchasing to displace the alternative combined cycle combustion turbines (when the purchase cost was less than fuel costs) was used to adjust the value of reserves (Jones, BPA, Exh. BPA-35, p. 10).

The third contractual condition of service raised by the ICP and the PPC is the provision limiting the duration of the restriction to 2 hours and the relationship of this restriction to the use by BPA of a 10 hour sustained peak adjustment. BPA is not claiming that the 10 hour sustained peak adjustment implies a flat 10 hour load exists during the day. In actuality, BPA's loads fluctuate dramatically over the course of a day, even during peak usage months such as January. The 10 hour reduction represents the amount that the instantaneous peaking capability needs to be reduced to reflect the inability of portions of the Federal system to peak consistently for a two week cold spell and maintain water in pondage plants. BPA's frequency and duration studies indicate that the expected outages in FY 1983 can be met with the 2 hour restriction rights in the DSI contracts (Jones, BPA, Exh. BPA-35, p. 21). BPA can shape the output of the FCRPS to meet peak loads during a forced outage, on an expected basis, as long as BPA can restrict delivery of power to the DSI's for 2 hours. Since the DSI's can meet expected outages on the system through the restriction rights, I believe the 2 hour limitation does not decrease the value of the reserves.

In the initial proposal, the forced outage reserve analysis sought to value the least cost alternative to the DSI restriction rights (Exh. BPA-7, p. C-11). Absent the DSI restriction rights, it was assumed that the Federal forced outage reserve requirements would be met by the installation of combined cycle combustion turbines (Exh. BPA-7, p. C-11). The annual cost of these facilities was calculated using a nominal interest rate of 15 percent. The ICP and PPC suggested that alternatives were available at a lower cost than the combined cycle combustion turbine. The suggested alternatives included purchase power, surplus capacity on the system, and a single cycle combustion turbine. After reviewing and examining these suggestions, I find that the combined cycle combustion turbine is the appropriate facility to value the forced outage reserves. I reject the use of purchase power for capacity since it would not be prudent for a utility manager to rely on purchases to meet reserve requirements. The DSI contracts provide reserves, through restriction rights, for twenty years. The availability and pricing of purchase power for capacity cannot be relied on to provide reserves on a long-term basis, and thus is not a suitable alternative to the DSI restriction rights. Instead, following judicious long-term planning assumptions, a utility would install standby generation. Surplus capacity on the system also cannot be relied on over the long-term to provide reserves for the system. Fluctuations in loads and resources make surplus capacity too unstable to provide reserves.

A single cycle combustion turbine is the least cost alternative for adding capacity at a low plant factor This conclusion is supported by BPA's TDLRIC Analysis. However, the alternative to the restriction rights also must be capable of providing for long-term energy outages. A combined cycle combustion turbine is an appropriate facility to provide both energy and capacity using long-range planning assumptions (Jones, BPA, Exh. BPA-35, p. 5). Long-term needs and uncertainties must be incorporated into the decision process. Future uncertainities as to fuel costs, limitations and restrictions, as well as unexpected and unpredicted changes in loads or resources lead to the decision to assume a combined cycle combustion turbine. For the final proposal, I have decided that a combined cycle combustion turbine will be used to measure the value of forced outage reserves.

The ICP, OPUC, and PP&L advocate the use of a real carrying charge in performing the value of reserve analysis (Shue, ICP, Exh. IO-17, p. 16; White, OPUC, Exh. SC-6, p. 10; Shue, PPL, Exh. IO-29, p. 8). These parties recommend this approach because a real carrying charge measures the savings associated with building a unit today as opposed to tomorrow. Thus, the real worth of an asset is not the annual nominal payment associated with the project but the payment minus the impact of inflation associated with delaying the unit.

The value of reserves analysis calculates the alternative to the DSI restriction rights. Without the DSI restriction rights, a standby generating unit would have been added to the system and BPA would have incurred yearly costs associated with this unit. A nominal carrying charge simulates the actual annual stream of costs (on a mortgage basis) associated with a particular project, based on BPA's current cost of money. Thus, a nominal payment pattern approximates the repayment obligations and cash flow, reflecting the actual demands made on customers to recover the costs associated with a particular project. Since the value of reserves analysis endeavors to measure the alternative to the restriction rights, I believe a nominal carrying charge is more appropriate. Parties contend that using a real carrying charge in the TDLRIC Analysis is inconsistent with using a nominal carrying charge in valuing forced outage reserves. BPA staff noted that the approaches taken in the two studies differ: the TDLRIC Analysis follows an economic approach and the value of reserves follows an engineering planning approach (Staff Eval., p. 55). I find that each of these have merit. For the reasons cited above the nominal carrying charge is appropriate for valuing the forced outage reserve.

For the final proposal, a nominal carrying charge is used over the life of the facility. The capital cost is based on the construction costs of Beaver escalated to 1983 dollars. A comparison of the escalated Beaver costs with current estimates for a similar project of General Electric indicates that the differences in costs are not significant (Jones, BPA, Exh. BPA-35, p. 7). The annual capital and maintenance cost associated with forced outage reserves is $94,379,000. The DSI's recommended that the annual cost be adjusted to reflect forced outages on the plants providing reserves. I do not believe this is appropriate in that the magnitude of reserves required is based on a percentage calculation designed to encompass such refinements. In addition, the alternative is composed of three plants each of which has six turbines and one steam unit plus one plant with four turbines and one steam plant. This substantially reduces the likelihood of major impact due to forced outage.

In the initial proposal, the value of stability reserves was determined as the annual cost of a load tripping scheme through isolating portions of the system (Exh. BPA-7, p. C-21). This was found to be the least cost alternative conforming with the BPA Reliability Criteria for System Planning and the Western System Coordinating Council Reliability Criteria for System Design. For the final proposal, I have decided to retain this approach.

The DSI's have proposed that this value include outage costs of interrupting regional consumers (Peseau, DSI, Exh. DS-3, p. 27). However, the determination of these costs is complicated since many are difficult to quantify, such as lost wages and profits, product spoilage, health and safety impacts, and simple inconvenience. Furthermore, these costs move from valuing an alternative to the DSI restriction rights to valuing the function of the reserves. I believe this movement would be inappropriate. For the final proposal, the value of stability reserves is $761,000.

In valuing the reserves provided by the DSI restriction rights for plant delay, the initial proposal assumed that since no new plants were scheduled to come on-line in the test year no operational costs as a result of plant delay would occur in FY 1983 (Jones, BPA, Exh. BPA-35, p. 10). Thus, no value was assigned to plant delay reserves. If plants were scheduled to come on-line in FY 1983, the Energy Reserve Planning Model (ERPM) would be used to determine the extent of the delay during the test year (Exh. BPA-7, p. C-9; Jones, BPA, Exh. BPA-75). Under this methodology, as the expected use increases the value of the reserves increases and similarly, as use decreases the value decreases.

I believe the DSI's raised some valid concerns with this approach. Their main objection was the absence of any effective guarantee that they would ever receive the credit for the regional benefit they provide (Peseau, DSI, Exh. DS-3, pp. 18-20). Since no binding commitment from BPA exists, they believe this method could be employed when the reserves were not used and then abandoned when BPA serves notice that the restriction rights will be used (Peseau, DSI, Exh. DS-3, pp. 18-20). Under the initial methodology, the impact resulting from plant delay could coincide with other adverse economic effects. Since the cost of the reserve credit is allocated to all power sales customers, this could result in the other customers being impacted by not only other adverse economic effects but also bearing the increased costs of the reserve credit.

To alleviate this potential, the DSI's proposed a levelized repayment pattern (Peseau, DSI, DS-3, p. 17-26). Under this pattern, costs of a particular project are spread over a planning horizon, distributing payments in the least disruptive manner. A levelized repayment pattern provides predictability and facilitates revenue stability and consistency. This approach recognizes the value of these reserves in providing insurance for the system against low levels of reliability over the entire planning period. Consistent with an insurance policy, payment is made every year and not just in those years when the claim is drawn upon.

The DSI's suggest that the correct approach to valuing plant delay reserves provided by the restriction rights is to look at expected slippage of the region's scheduled baseload plant additions over the planning horizon, using ERPM (Peseau, DSI, Exh. DS-3, pp. 16-17). The calculated energy deficits would then be adjusted to recognize the energy shortages that could be covered by expected surplus. I believe this idea has merit and have directed staff to review and analyze this proposal. However, time constraints have prevented consideration of this proposal for this rate filing. Instead, the final proposal will adhere to the approach used for the initial proposal. Thus, no value is assigned to plant delay reserves.

3. Special Industrial Rate, SI-2

Section 7(d)(2) of the Regional Act allows the Administrator to establish a special rate for any DSI customer using raw materials indigenous to the region, providing the following conditions are met: (1) it is determined that this customer will suffer adverse effects from increased rates pursuant to the Regional Act, and (2) the rate includes a provision that all power sold to such a customer may be interrupted or withdrawn to meet firm loads in the region.

Hanna testified that it would suffer adverse impacts from increased power costs if the proposed IP-2 rate were applied to BPA's sales to

Hanna. Although currently Hanna would need a rate of about 2 mills per killowatthour to operate economically, a rate similar to the SI-2 rate in the initial proposal would increase the likelihood of operation if the market for nickel improved (Wedge, Hanna, Exh. DS-6, pp. 16, 18-21; TR. 3069).

Based on this testimony, I find that Hanna will experience adverse impacts if BPA's proposed IP-2 rate is applied to Hanna. I find that all power sold to Hanna may be interrupted or withdrawn to meet firm loads in the region. I also have concluded that a special rate for Hanna will not adversely impact BPA's other obligations under the Regional Act. I have therefore again approved, for application solely to sales to Hanna, a special rate under Section 7(d)(2) of the Regional Act.

During the hearings, the granting of a special rate for Hanna was opposed because Hanna was not in operation and might not resume operation in FY 1983 (Wolverton, PPC, Exh. PB-9, p. 3; Wolverton, PPC, TR. 2245). I am unaware of anything in the legislative history or the Regional Act itself that requires a DSI, in order to qualify for a special rate under Section 7(d)(2), to be in operation at the time the rate is established in order to qualify. From a practical standpoint, it would be an expensive and untimely proposition for BPA and Hanna to begin negotiating a special rate only after market conditions have improved such that profitable operation is possible. Furthermore, Section 7(d)(2) was created to prevent adverse impacts on Hanna's operations as a result of the Regional Act. Hanna submitted testimony which indicated that, without the special rate, its ability to resume nickel operation would be more difficult. The adverse impacts presented pertain to Hanna's ability to reopen and continue operations in the future.

It also was argued that because Hanna has not demonstrated that adverse impacts would result from increased power rates, it should not be eligible for the special rate. This argument was based on Hanna's failure to cite the new power rates as one of the reasons for the plant closure in May of 1982 (City of Seattle Opening Brief, p. 20). Although not mentioned explicitly, power costs were listed as one of four major components of production cost, and production costs were cited as one of the reasons for the shutdown (Wedge, Hanna, Exh. DS-6, p. 5).

In the initial proposal, the Hanna rate was based on allocated costs less the net savings to BPA of serving Hanna's second quartile with interruptible power. BPA determined the savings based on the long run incremental cost of generation less the average nonfirm rate foregone by providing such service. This represented BPA's savings from not having to acquire resources to serve the second quartile. The PPC, PP&L, and APAC, in their briefs, discussed perceived miscalculations and incorrect application of the methodology for determining the Hanna adjustment.

I have reviewed these criticisms and agree that it is inappropriate to use the TDLRIC to value the interruptible second quartile both because of the regional surplus (Wolverton, PPC, Exh. PB-9, p. 4-5) and Hanna's termination rights (Wolverton, PPC, Exh. PB-9, pp. 3-4; TR. 1849-50).

However, I also agree with Hanna that the Regional Act requires no cost justification to provide Hanna with a special rate (Hanna Reply Brief, p. 2).

Section 7(d)(2) of the Regional Act provides for the special rate "in order to avoid adverse impacts of increased rates pursuant to this Act" on specified DSI customers. Therefore, I have decided to set the Hanna rate equal to the Priority Firm rate less the credit for value of reserves. This represents a reasonable estimate of what the rate to Hanna would have been without the Regional Act.

4. Wholesale Firm Capacity Rate Schedule, CF-2

a. Description

The CF-2 rate schedule supersedes the CF-1 rate and applies to utilities purchasing firm capacity from BPA on either a yearly or seasonal basis. Annual capacity is delivered throughout the year as requested by the customer and seasonal capacity is delivered over the 5 month period of June 1-October 31. Energy associated with this capacity is to be returned to BPA. The rate also includes a surcharge for capacity taken in excess of 9 continuous hours per day.

b. Sustained Peaking Surcharge

To encourage capacity purchasers to limit their use of Federal generating facilities and maximize use of their own facilities, the CF-2 rate includes an additional monthly charge for capacity taken in excess of 9 consecutive hours per day. This 9 hour period is based on a study which determined the equivalent load duration of BPA's PF-2 and IP-2 sales. By using a 9 hour period I am permitting CF-2 customers to take power for as long a period as would be required by PF-2 and IP-2 customers if they had the flexibility to purchase power under a capacity-only rate. The charge that I have imposed for taking excess capacity is based on the reduction in peaking capability caused by additional hours of demand duration.

The PGP argued that this surcharge penalizes them and provides an incentive to construct unnecessary peaking capability (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, p. 40). In response to this comment, I reviewed the method used to develop the initial proposal. In the initial proposal the cost of moving from a 9 hour to a 15 hour duration peak was determined by multiplying the corresponding reduction in hydro peaking capability (in megawatts) times the unit cost of the FBS capacity (capacity costs per FBS megawatt billing determinant). Because the peaking capability of the hydro system exceeds the FBS billing determinants, this may have overstated the cost of the peaking capability reduction. In determining the surcharge for the final proposal, the cost of the peaking capability reduction was determined by multiplying the percentage reduction in peaking capability by total FBS capacity costs.

Since the charge is cost-based, it is not a penalty and it provides appropriate price signals to the customer. That is, customers will build peaking facilities rather than exceed the 9 hour limit only if the cost of those facilities is less than the cost to the Federal system of providing additonal hours of demand duration.

5. Wholesale Emergency Capacity Rate Schedule, CE-2

The CE-2 rate supersedes the CE-1 rate and applies to emergency capacity provided to utilities on a weekly basis, when available. The energy associated with the delivery of this capacity must be returned. BPA will provide short-term capacity sales only when an emergency exists and when BPA has capacity available. The rate for a CF-2 contract year was divided by the number of weeks in a year and the resultant cost was increased by 15 percent to cover associated administrative and general costs. This results in a rate of $0.81 per kilowattweek for deliveries in the Pacific Northwest. Because costs associated with deliveries over the Pacific Northwest-Pacific Southwest Intertie have not been allocated to this service category in the COSA, these deliveries are subject to an additional charge of $0.19 per kilowattweek. This charge was derived by dividing the intertie costs allocated to CF-2 seasonal capacity in the COSA by the billing determinant for CF-2 seasonal capacity.

6. Wholesale Firm Energy Rate Schedule, FE-2

The FE-2 rate schedule replaces the FE-1 rate schedule. This rate is designed to provide firm energy to purchasers with contracts in effect prior to October 1, 1982, which refer to this rate or its successors. Energy is provided in the amounts and during the periods specified in their contracts. The rate is based on the PF-2 rate, assuming a 100 percent load factor. It includes an adjustment for power factor.

Delivery of energy under this rate is assured during the contract period. However, BPA may interrupt the delivery of firm energy, in whole or in part, at any time that BPA is unable to make delivery because of system operating conditions.

7. New Resource Firm Power Rate, NR-2

Section 7(f) of the Regional Act requires BPA to establish the New Resource Rate, NR-2. It is available for the purchase of firm power for resale or direct consumption by regional IOU's under net requirement contracts and for new large single loads of a public body, cooperative utility or Federal agency.

In the initial proposal, the NR-2 rate was constructed with a base rate which was based on the lowest cost resources assigned to serve the new resources load. The NR-2 rate was to be equal to the base rate until the total purchases exceeded the annual average output of the lowest cost resources. Thereafter, the NR-2 rate would have increased as the IOU requirements load increased and BPA purchased additional resources to serve the load. This rate was designed to assign the lowest cost available resources to Pacific Northwest requirements customers while at the same time insuring that BPA would fully recover its costs if the NR load differed significantly from that forecasted.

Both the ICP and PPC advocated a fixed NR rate. The ICP stated that it should be based on the lowest cost surplus resources (Deesen, ICP, Exh. IO-14, pp. 13-14) whereas the PPC said it should be based on a melding of resources (Wolverton and O'Meara, PPC, Exh. PB-32, pp. 2-5). I have decided to base the NR-2 rate on the cost of the exchange resources to reflect the costs of those resources most likely to be associated with an NR load. The need for a flexible rate or for basing the rate on a meld of exchange and new resources is obviated by the closeness in unit costs between the exchange resources and the non-discretionary new resources. The testimony in the hearings that there will be little or no NR load in FY 1983 (Allcock and Wolverton, JCP, Exh. JCP-3, p. 3). Thus, the potential underrecovery caused by this rate form is negligible.

8. Surplus Firm Power Rate, SP-1

This is the first year in which BPA has developed a surplus firm power rate. In the initial proposal, the SP-1 rate had two components, one for the sale of exchange power made available because of load underruns or curtailments, and one for the sale of specified resources. The first component was based on specific resources and had specific demand and energy charges. The energy charge in the second component was identified as the "annual cost of the identified resource or resources" plus a 5.0 mill adder.

Many parties commented that the terms and conditions for sales under the SP-1 and SE-1 rate schedules were not clearly identified. It was suggested that a minimum number of days duration should be given to differentiate this service from NF-2 (Alexanderson, ICP, TR. 305-6; Parmesano, LADWP, Exh. CU-4, pp. 5, 11; Metague, PG&E, TR 6-7, 10). I believe that the specific terms and conditions for power sales under the SP-1 and SE-1 rates should be included in the power sales contracts. I do not agree that these kinds of terms belong in the rate schedule. It is impossible to foresee precisely the market conditions which will prevail during the rate year, and BPA must be able to tailor the terms of sale to the needs of the individual customer. For example, some may desire to purchase blocks of power over a number of months whereas others may need greater flexibility. Parties have emphasized the importance of aggressive marketing of BPA's surplus (DSI Opening Brief, pp. 85-90), and I believe that too much specificity with regard to conditions of sale in the rate schedule may hamper this effort.

The rate section of the schedule was also criticized for its lack of specificity and clarity. It was suggested that the resources being sold and their costs should be more clearly identified. In contrast to the initial proposal, I find that it is now possible to identify the resources to be sold under SP-1. The size of the surplus has been identified and costs allocated to it in the COSA. The SP-1 rate has been developed in the same manner as the rate for other firm services. Costs allocated to the service include the surplus portion of the exchange resources, the nondiscretionary new resources, transmission, conservation, deferral, and BPA administrative costs. The costs of the new resources have been reduced to reflect displacement with nonfirm energy and an allocation of excess revenues.

It was necessary to include a formula rate for the sale of the discretionary resources because of their uncertain costs. This component will allow BPA to sell new resources (if any) acquired during FY 1983 at cost while holding purchasers under other firm rate schedules harmless.

9. Surplus Firm Energy Rate SE-1

Because it is possible to have surplus firm energy without surplus capacity in the FCRPS, and possible to market surplus firm energy, I am offering a surplus firm energy rate, SE-1, in this final proposal. The final proposed SE-1 rate is designated for the purchase of surplus energy for resale or for direct consumption by all customers other than DSI's. It is available for purchase both inside and outside the Pacific Northwest and outside the United States.

I will base the SE-1 rate on the costs of surplus resources that have been allocated to the surplus firm power rate, SP-1. Consequently, the SE-1 rate will be set at the same level as the SP-1 energy charge. As I proposed for the SP-1 rate, other specific conditions of sale under SE-1 will be determined in individual contracts transacted with eligible customers.

10. Wholesale Nonfirm Energy Rate Schedule, NF-2

a. Description of the Rate

The NF-2 nonfirm energy rate is substantially different in structure than the NF-1 nonfirm energy rate. The NF-2 rate was designed to address concerns raised by the parties about BPA's previous nonfirm energy rates, the NF-1 rate and its predecessor, the H-6 rate. The NF-2 rate has three components: the standard rate, the spill rate, and the incremental rate. The standard rate is 18.2 mills per kilowatthour. It will be in effect except during those times when a spill or imminent spill condition exists on the Federal system as a result of an excess of nonfirm energy above available markets. Under the standard rate, 50 percent of each maximum hourly amount will be offered with a guaranteed delivery provision. This guarantee extends for the maximum number of days practicable.

The spill rate will be applied when a spill or imminent spill condition exists at one or more FCRPS hydroelectric plants as a result of an excess of energy on the FCRPS above available markets. The spill rate is 9 mills per kilowatthour. The incremental rate will be applied to sales of energy that have an incremental cost greater than 16.2 mills per kilowatthour (the standard rate less two mills per kilowatthour). Energy sold under the incremental rate is energy produced or purchased by BPA concurrently with the nonfirm sale that BPA would have the option of not producing or purchasing if it were in BPA's economic interest. The rate is equal to the incremental cost of producing or purchasing the energy plus two mills per kilowatthour.

An alternative to the 3-part rate was proposed by the PPC and PGP, who advocated a share-the-savings rate (Garman, Opatrny, Knitter, and Sunday, PGP, Exh. PB-20, pp. 60-61; Wolverton, PPC, Exh. PB-9, p. 11). BPA implemented a share-for-savings rate design in 1979 and found it extremely difficult to administer because of difficulty in monitoring the resources being displaced by Northwest and California utilities. I believe that the proposed NF-2 rate reflects the value of the nonfirm energy, shares the costs equitably between firm and nonfirm service, and has increased the predictability of the rate.

b. Standard Rate

The standard rate is determined by dividing BPA's total costs, excluding exchange costs, by total firm and nonfirm energy sales, excluding exchange energy. Exchange resource costs and exchange energy are both excluded from the calculation because the exchange resources have no direct effect on the availability of nonfirm energy on the Federal system. Fundamentally, this rate is an average of all the costs associated with an electric utility power supply system spread over all power sales.

A standard rate based on BPA's average system costs excluding exchange costs is a reasonable approximation of the cost of nonfirm energy service recognizing that FBS resources (defined by statute) and new resources including conservation contribute to the availability of nonfirm energy. The ICP utilities will buy the majority of their purchases of nonfirm from BPA at the standard rate. The ICP agrees that the standard rate determination is a fair approximate reflection of the cost of nonfirm energy service (Schultz, IPC, Exh. IO-25, pp. 1-2). The PPC (TR. 5962-4) and the PGP (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, p. 60-62) concur that the NF-2 standard rate is fair and reasonable.

The California parties disagreed with the calculation of the standard rate, arguing that the rate should not include costs that do not contribute to the availability of nonfirm energy, thus excluding the Supply System costs and deferred interest and amortization costs (Parmesano, LADWP, Exh. CU-4, pp. 2-3). The California Public Utilitites Commission argued for the exclusion of the Supply System costs because nonfirm energy customers now do not receive a benefit from the Supply System plants and are not assured of a benefit in the future (Barton and Mattson, CPUC, Exh. CC-1, pp. 6-7). While the NF-2 rate is a cost based rate, BPA's nonfirm energy rates are not required to be based on cost of service (see Memorandum of BPA Counsel, pp. 66-85).

I do not agree that only costs of resources which directly contribute to nonfirm energy should be included in the standard rate. Many costs that are not resource costs are incurred as support services for power generation. For example, operation and maintenance services are necessary for continued resource operation. Inclusion of the Supply System costs in the standard rate is consistent with the definition of FBS resources. As stated in the Transcript (TR. 1661), the Regional Act includes the Supply System projects in the definition of FBS resources. Thus, the costs of the projects are included in the costs of the FBS. The majority of nonfirm energy is made available from FBS resources. The Supply System plants are baseload resources with low incremental costs, such that when they do come on line, they will help provide a continued supply of nonfirm energy at low cost. Therefore, by including Supply System costs in the standard rate, nonfirm customers receive the benefit of lower cost FBS resources and pay a rate based on the total costs of the FBS and not just a portion of the cost. BPA is contractually required to pay certain Supply System costs before they come online. In addition, nonfirm energy customers will be receiving the benefit of the additional supply of power when the Supply System projects become operational. If nonfirm customers avoid paying any Supply System costs until the plants become operational, they will receive the benefits of the Supply System plants without paying the full cost.

When BPA develops rates, it must do so on a prospective basis. Projections of sales are based on average operating conditions, and on our best estimate of what the loads and associated costs of serving those loads will be. The resulting rates can either underrecover or overrecover, depending on the accuracy of the numerous estimates of what will occur to what actually occurs. The cumulative deferral is a result of this dynamic process of designing rates prospectively, as all utilities must do, and thereby not recovering revenues that exactly match the costs. I have decided that it is most equitable to allocate the deferral costs to all customers, because the deferral cost is incurred by the system as a whole. I further conclude, therefore, that this is an appropriate cost to be included in the standard rate.

Another issue raised by the California utilities concerned the inclusion of capacity costs in the standard rate. They argue that delivery must be guaranteed for 3 days to appropriately include capacity costs (Metague, LADWP, Exh. CU-5, pp. 4, 8-9). The PPC indicated that it was appropriate for all rate payers to pay some fixed costs (Wolverton, PPC, Exh. PB-9, p. 11). Although the proposed NF-2 standard rate is based on costs, BPA also is attempting to reflect value and equity considerations. Nonfirm energy customers are receiving the benefits of installed generation; it is equitable that these customers also should pay some of the fixed costs.

The California parties suggest that NF-2 rate is not consistent with the determination order adopted by BPA pursuant to PURPA Section 111. To the contrary, I believe that BPA is conforming properly with the cost of service determination of Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 95-917, 92 Stat. 3117 et seq. (16 U.S.C. 2601 et seq.). After adopting the cost of service standard, BPA states:

> ". . . 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."

Thus, it is clear that other factors in addition to a COSA must be considered when designing rates. The court in Pacific Power & Light Company, 499 F. Supp. 672 (D. Or. 1980), appeal dismissed, No. 80-3517 (9th Cir. Feb. 13, 1981) when faced with an allegation that non-cost based rates violated BPA's PURPA 111 Order expressly held that such rates do not, saying:

> "Despite all the references to cost (in the PURPA Order and Section 7 of the Bonneville Project Act) the two quoted passages do not support an inference that cost is the only basis upon which rates may be computed . . .
>
> ". . . This BPA regulation, promulgated pursuant to (PURPA Section 111) has not been violated because the BPA considered cost-of-service factors in its calculation of rates. This is all the PURPA requires." Id. at 683 (emphasis in original).

c. Guaranteed Delivery

BPA's initial proposal provided that BPA will guarantee delivery of one-half of the energy BPA offers for sale each hour at the NF-2 Standard Rate except under certain narrowly-defined conditions. This provision, like several other aspects of the NF-2 rate, represents what BPA believes to be an acceptable compromise for pricing and delivering NF-2 energy. Despite numerous arguments, especially from the California parties, that a greater or longer guarantee should be given to achieve a greater value and useability of the power, I have determined that, as a practical matter, at this time BPA cannot go beyond the initial proposal with respect to guaranteed delivery and thus it should be adopted in BPA's final NF-2 Rate schedule.

If 50 percent of the energy were offered to each customer on a guaranteed basis, and if all purchasers bought guaranteed energy only, BPA would sell as guaranteed an amount of nonfirm energy greater than 50 percent of the total nonfirm offered (Yamamoto, LADWP, Exh. CU-3; Metague, PG&E, Exh. CU-5, pp. 3-4). California parties argued that at least 50 percent of the NF-2 Standard Rate energy which BPA offers to each customer should be guaranteed, and that the offer to schedule energy in advance should extend for 3 days (Yamamoto, LADWP, Exh. CU-3; Metague, PG&E, Exh. CU-5, pp. 3-4). Northwest public agencies (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-15, p. 61) and investor-owned utilities (Schultz, ICP, Exh. IO-25, pp. 5-7) are concerned that any guarantee may decrease the availability of nonfirm energy. Because of the nature of nonfirm as the "last available" power from the system and its associated unpredictability in the PNW hydro system, increasing the percent offered on a guaranteed basis above 50 percent or extending the guarantee for 3 days would tend to reduce the amount of NF-2 energy BPA would reasonably be able to offer for sale.

power from the system and its associated unpredictability in the PNW hydro system, increasing the percent offered on a guaranteed basis above 50 percent or extending the guarantee for 3 days would tend to reduce the amount of NF-2 energy BPA would reasonably be able to offer for sale.

BPA actively considered the delivery of nonfirm energy on a guaranteed delivery basis for 3 days in advance on all scheduling days including, for example, Monday through Thursday of a normal work week, and concluded that it would cause serious problems. Currently PNW utilities each workday establish scheduled deliveries of power (prescheduled) by hours, through what both utilities observe as a normal workday. If BPA were to arrange schedules of NF-2 for additional days, BPA would be scheduling nonfirm energy before it knew the amounts of firm power that might be taken under firm power contracts. Furthermore, because of the inter-relationship between Federal and non-Federal hydro facilities, BPA would be unable to adequately predict the availability of power until the water releases among the several projects could be coordinated commensurate with the scheduled power amounts. These only occur with sufficient reliability for days where the power has been prescheduled. Under these combined circumstances, BPA would have to effectively limit the amounts of NF-2 energy made available on a guaranteed delivery basis to only those amounts which would remain after the maximum use by all higher priority contracts was combined with only the assured, as opposed to the probable, water supply. These reservations would cause BPA to offer little or no energy for scheduling under the NF-2 rate on days which were not yet being prescheduled. I considered whether BPA might offer very limited amounts of NF-2 power beyond the prescheduled days for the second and third ensuing days, and then offer additional NF-2 energy when those days become prescheduled days. However, the practice of offering large additional amounts under these circumstances would constitute a breakdown of any arrangement wherein the purchaser expected to have substantial amounts of NF-2 energy prescheduled on a guaranteed delivery basis for up to three days in advance. In effect it would render the purpose of a guarantee for any days beyond the prescheduled days as meaningless.

For these reasons, I decided that it was better to offer NF-2 energy on a guaranteed delivery basis only for those days on which all power deliveries were being prescheduled and the guarantee could, in fact, be supported. Therefore, BPA will, as stated in the initial proposal, preschedule deliveries of NF-2 standard rate energy only "for the next day or days over which nonfirm energy is normally prescheduled in the Pacific Northwest," which is normally one day in advance except on weekends and holidays when it can extend up to four days.

The California parties proposed a scheme under which guaranteed energy would be delivered for three days, but would be subject to return under certain circumstances (provisional deliveries) (Yamamoto, LADWP, Exh. CU-3). Although the approach has merit under some situations, there are too many circumstances under which BPA's generating system will not be able to make the deliveries even on a provisional basis. This occurs whenever there is insufficient water in the reservoirs to provide the power and generating capacity requirements. BPA witness Lawrence A. Dean explained the pondage problem BPA encounters in operating the FCRPS (TR 5545). The FCRPS is predominately a hydro system which has generator installations at hydro plants that are able to generate well in excess of the average daily or weekly inflow at that plant. By absorbing the inflow during low power needs and augmenting it during heavy power needs, energy can be moved from hour to hour and occasionally day to day. Any time that the outflow exceeds the average outflow, or essentially the inflow, water is removed from the reservoir behind that dam. BPA has a limited ability to remove water from many FCRPS reservoirs. Such reservoirs include Bonneville, The Dalles, John Day, McNary, Ice Harbor, Little Goose, Lower Granite, Lower Monumental, and Chief Joseph. These plants constitute well over half the installed capacity of the FCRPS.

So, when we are delivering energy during the daytime hours, we are taking water out of limited reservoir capacity behind those dams. If we do that to an excessive extent, we deplete the water behind those dams and our ability to generate is reduced to the inflow at the time. This is the source of operating problems in delivering firm and nonfirm energy during the heavy load hours. If greater power requirements and/or lower inflows occur than anticipated on the day of the guaranteed delivery, the available reservoir capacity may be exceeded. Having that power returned at a later time as suggested by the California parties does not mitigate this problem. This also is one of the limitations on our making nonfirm energy available for sale during the heavier load hours. If we over-extend ourselves on guaranteed nonfirm sales during those hours, we are going to again deplete the water behind the dams, and be unable to generate power in excess of inflow. Normally the inflow is just a small fraction of the installed peaking capability at these projects and, if no reservoir capacity is available, this situation would result in a serious reduction of peaking capability.

Nevertheless, BPA commonly puts as much of its nonfirm energy into the daytime or heavy-load hours as it reasonably can in order to improve the marketability and/or useability of this power. Unexpected events such as forced outages, increases in loads, or sales under higher priority power sales contracts would decrease the amount of energy available during a span of heavy-load hours in the case of pondage limitations or on a particular hour in the case of capacity limitations.

If BPA could not reduce its obligations to deliver nonfirm energy when it encountered some unexpected limitation in its ability to deliver guaranteed nonfirm energy, the ability to obtain the return of that energy within a few days by converting those schedules of energy deliveries into provisional deliveries would not resolve capacity or pondage problems. When BPA encountered a pondage limitation, to be effective, the return would have to be completed before the end of the heavy-load hours during which BPA would otherwise exceed the pondage limitation, a matter of only a few hours in many cases. Under these conditions the benefit of a guarantee is virtually unobtainable.

Although the provisional delivery scheme proposed by the California parties does not solve the difficulties identified, BPA recognizes the added value and will strive to make its best estimate of available nonfirm energy for the second and third days beyond prescheduled available to potential purchasers although it cannot be offered on a guaranteed delivery basis. Furthermore, we will continue to work with the Northwest purchasers of nonfirm energy as well as the California utilities in a continuing effort to best accommodate their collective needs with regard to deliveries of nonfirm energy.

California parties are concerned that Northwest purchasers could subscribe to all the guaranteed energy leaving all non-guaranteed energy for California purchasers. BPA does not know whether this condition might occur, but BPA believes that this situation will not occur persistently. BPA anticipates that the take-or-pay provisions of the guaranteed energy will provide a significant disincentive for the Northwest purchasers. In addition, BPA anticipates that during most seasons of the year Northwest purchasers will either be taking all of the NF-2 standard rate energy BPA offers for sale or they will be taking almost none of it. Under these circumstances, the guaranteed and non-guaranteed portions will not be stratified between Northwest and California purchasers. Furthermore, not offering all of each type of energy (guaranteed energy or non-guaranteed energy) which BPA makes available for sale on a given hour to each of its priority classes of customers until that energy is fully subscribed may violate BPA's public agency and Pacific Northwest preference obligations.

Finally, both Northwest public agencies and investor-owned utilities testified that they would prefer to have none of the NF-2 standard rate energy offered on a guaranteed basis. I believe that the compromise of a guarantee of one-half of the energy for one day is workable and will not significantly reduce the amount of nonfirm energy which BPA will make available.

d. Spill Rate

The 9.0 mill spill rate is based on the value of spill energy to Northwest thermal operators. I believe that the standard rate is the appropriate NF rate based on costs. However, I recognize that when energy on the Federal system cannot be conserved, it does not make good environmental or practical sense to not use this otherwise spill energy to displace generating projects which are using depleteable fuels such as coal, gas, and oil. Therefore, I decided to take a reduction in the sale price sufficient to economically displace thermal generation. In establishing the spill rate on this basis, I eliminated the lowest incremental cost plant, which in the test year was Wyodak, from consideration.

The California utilities believe the spill rate should be based on the costs BPA incurs to run its hydro plants, using the same method as was used for determining the NF-1 floor rate; i.e., the average hydro cost (Metague, PG&E, Exh. CU-4, p. 8; Parmesano, LADWP, Exh. CU-4, pp. 7-8). The Northwest utilities, on the other hand, agreed that the displacement of Northwest thermal plants provides a reasonable standard for determining the spill rate. The spill rate represents a price at which BPA may sell nonfirm to avoid total loss of revenue due to market conditions (Saleba, Russell, Schneider, and Hutchinson; WPUD's, Exh. PB-15, p. 22; Schultz, ICP, Exh. IO-25, pp. 2-4).

The 9.0 mill spill rate is significantly below that needed to economically displace the energy of California utilities, particularly during the spring runoff spill period. During the spring and early summer, California is usually assured of a large, continuous supply of nonfirm energy. BPA sells the same product all year long and the standard rate is the cost-based rate for that product. It is the marketing conditions that vary and force BPA to charge less than the cost-based rate when a spill condition exists.

Experience has shown that the level of the nonfirm rate will play a major role in the decision to shut down thermal plants. While there are other factors involved in the decision to shut down, such as take-or-pay fuel contracts, storage ability, peaking requirements and thermal operations, the cost of alternative energy is a primary consideration. The ICP concurs with this view when they suggest a 1 mill lower spill rate would shut down regional coal plants to the maximum extent possible (Schultz, ICP, Exh. IO-25, p. 4).

I removed Wyodak from consideration in determining the spill rate because the cost of Wyodak seemed unusually low compared to the other plants. The ICP witness suggested that the spill rate be lowered to include consideration of Wyodak (Schultz, ICP, Exh. IO-25, p. 4). The inclusion of Wyodak would have changed the spill rate by at least 1 mill would have a significant effect on revenues. The ICP position that the spill rate should be lowered approximately 1 mill in order to displace one additional coal plant must be balanced against the revenue expected to be lost by such a lowering since the rate applies to all nonfirm sales. Also the ICP witness admitted that other factors might cause Wyodak to continue to operate even if the rate were lowered (TR. 4769).

The WPUD's suggested that the spill rate should be set at or above the average operating cost of Northwest thermal to reflect the value of the energy, asserting that such an increase will not change the amount of coal burned, coal orders, or thermal plant operations (Saleba, Russell, Schneider, and Hutchison; WPUD, Exhibit PB-31, pp. 22-23). However, I find that this proposal would result in a spill rate above the incremental cost of many regional coal plants with the possibility of a significant loss in efficiency.

In the initial proposal, the spill rate was diurnally differentiated using the same spread between the peak and offpeak charges for energy from hydro resources that appears in the current NF-1 rate. The spill rate was time differentiated to encourage the Corps of Engineers and the Bureau of Reclamation to perform maintenance and repair work on the hydroelectric generating units during offpeak hours. I have decided not to time differentiate the spill rate for the final proposal. I do not believe the differentiation between peak and offpeak hours in the spill rate would have any substantial effect on purchase of such energy or the operation of the projects, particularly the decisions about maintenance and repair of the hydroelectric units. Furthermore, since the rate is based on value, we did not identify a basis to differentiate the cost diurnally.

e. Incremental Rate

The major issue raised with regard to the incremental rate concerned the amount of money that would be added to the incremental cost of producing or acquiring the power. This incremental cost is determined by identification of all identifiable costs in mills per kilowatthour which BPA would not have incurred if it had chosen not to produce or purchase the power being sold under the incremental rate. In the initial proposal, BPA included a 15 percent adder with the proviso that the total charge was limited to the fully distributed cost of the resource. The California utilities claim there is no cost justification for the 15 percent adder. They suggested a 1 mill adder would cover hard-to-identify operating costs (Metague, PG&E, Exh. CU-5, pp. 5-6; Mattson, CPUD, Exh. CC-1, pp. 15-16).

In determining the adder for sales under the incremental rate, BPA first determined what it would pay other utilities under current contracts for purchases of nonfirm energy. Since a 15 percent adder is a provision of current BPA contracts with California utilities, this appeared to be a reasonable adder for the nonfirm incremental rate. Additionally, while the total charge in the initial proposal under the incremental rate is limited by the fully distributed cost of the resource, the 15 percent adder gives some incentive for BPA to operate a resource to make the sale. Although the 15 percent adder is not cost-based, the limit is cost-based.

However, I agree that the 15 percent adder may be excessive given the escalation in costs since the signing of the contracts with the California utilities. The Californians gave no support for the choice of 1 mill as an adder. It appears to be derived from a FERC rule (Order no. 84, issued May 7, 1980) which allows adders up to 1 mill without cost justification by third party transmitters. The draft rule contained a 2 mill limit for generating utilities although no limit was adopted for generators in the final rule. It is clear that a larger adder is needed by a generating utility than by a third party providing wheeling and I have therefore adopted a 2 mill adder. This level also represents a reasonable compromise between the initial proposal, which would result in a 4.5 mill adder for a 30 mill resource, and the 1 mill proposal by the Californians. I will be watching with interest any use of the 15 percent adder applied to purchases under our contracts with California utilities.

f. Conclusion

BPA staff has calculated that the average nonfirm rate for sales under this schedule will be 11.2 mills per kilowatthour, which is an average rate far less than the average rate for any other rate schedule developed for this filing. Although the California utilities have objected to various costs included in the standard rate, it should be noted that this rate is considerably lower than the maximum rate which would have resulted from alternative rate designs such as share-the-savings which are widely used by electric utilities for nonfirm sales.

The California parties also object to the use of value of service principles. Indeed, it is clear that the value of the nonfirm power to California is much greater than 11.2 mills per killowatthour; the total benefit to California from BPA's nonfirm energy sales to California will be much greater than the benefit to the Pacific Northwest from those sales. Thus, I do not think that charges of value of service pricing or revenue maximization are reasonable. The value of service is reflected in the spill rate but only because it is necessary to <u>lower</u> the rate because of market conditions (Shultz, ICP, Exh. IO-25, pp. 2-3). It would benefit no one if I were to leave the rate at the cost-based standard rate and let the water spill over the dams.

Finally, much is often made of the very low short run incremental cost of generating nonfirm from hydroelectric facilities and the fact that resources are not planned to serve nonfirm loads. However, this argument overlooks the fact that "nonfirm energy is available to California as a result of the decision in the Pacific Northwest to build sufficient baseload generation to meet Northwest loads under critical water conditions" (PP&L Opening Brief, pp. 28-29). A reasonable amount of revenue from nonfirm energy sales is needed to make this resource plan more economic than the alternative of planning for average water and operating combustion turbines and making purchases during adverse years (TR. 5144-55). Thus BPA's resource mix and the cost thereof is influenced by the nonfirm energy market.

11. <u>Energy Broker Rate, EB-1</u>

No substantive comments, issues or criticisms were raised in the record regarding the Energy Broker Rate, EB-1. Consequently, I will adopt the EB-1 rate as presented in the initial proposal. As indicated in the initial WPRDS, BPA entered into an agreement with the Western Systems Coordinating Council (WSCC) to participate in WSCC's Energy Broker program and will use the energy broker system to communicate, match and schedule the buying and selling of electric energy with other program participants. The broker will be used by BPA only after all available markets have been served under the nonfirm energy rate schedule and energy would otherwise be spilled. Once nonfirm energy is offered on the Broker, public agency and regional preference will no longer be a factor in determining who will purchase nonfirm energy. Both buy and sell transactions will be negotiated on an hourly basis and are interruptible immediately upon notification.

BPA also may act as a broker in the WSCC system for its customers when energy is desired to be sold by those customers on the Broker. Power sold in this manner will be from previously stored energy in the FCRPS and would not include service, storage, wheeling, or duration charges that BPA assesses its customers for storage service.

12. <u>Reserve Power Rate Schedule, RP-2</u>

The RP-2 rate schedule replaces the RP-1 rate schedule and applies to purchases of: (a) firm power to meet a purchaser's unanticipated load growth as provided in the purchaser's power sales contract; (b) power for which BPA determines that no other rate schedule is applicable; 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 the purchaser and BPA determines the rate should apply.

This rate schedule is derived directly from the results of the TDLRIC Analysis. The demand charges reflect the incremental costs of capacity based on the costs of a single cycle combustion turbine adjusted for an energy credit and selected incremental transmission facilities. The energy charge reflects the incremental cost of energy based on baseload thermal cost adjusted for a capacity credit. The demand charge is both seasonally and diurnally time differentiated. The energy charge is not time differentiated. An adjustment for power factor is included.

13. <u>General Rate Schedule Provisions (GRSP)</u>

The Wholesale Power Rate Schedules include the GRSP section which defines the terms found in the rate schedules. It was suggested that the fundamental definitions and sections regarding billing and billing data should not be in the GRSP's, but rather in the power sales contracts where they are subject to review and modification (Garman, Opatrny, Knitter, Sunday and Long, PGP, Exh. PB-20, pp. 47-50). While I agree that some of the provisions and billing information is duplicative, I believe it is important to have information in both contracts and rate schedules. Not all customers have signed contracts. Also, our rate schedules are used as reference material by non-customers and must, therefore, be able to stand alone.

VIII. National Environmental Policy Act

A. Introduction

The National Environmental Policy Act (NEPA) is our basic national charter for protection of the environment. It establishes national policy, sets goals, and provides procedures for carrying out environmental policy. NEPA requires a Federal Agency to prepare environmental documentation to accompany every recommendation or report on proposals for major Federal actions which may significantly affect the quality of the environment.

Under NEPA, when it is determined that a given major Federal action has the potential to significantly affect the quality of the environment, an Environmental Impact Statement (EIS) is prepared. 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 June 25, 1982. Subsequent to the close of the formal rate hearings, a Final EIS was prepared based on the Draft EIS and comments received on the Draft EIS. Copies of the Final EIS are available upon request from the BPA Environmental Manager.

B. Wholesale Rate Filing

1. Decision

I have decided to submit to the FERC a proposal to adjust BPA's wholesale power rates in order to achieve total revenues of $2.2 billion in FY 1983. This revenue level is approximately $200 million less that the revenue level in the initial proposal. The decisions I made regarding the proposed wholesale power rates are incorporated into the wholesale power rate schedules attached as Exhibit A. I have made these recommendations based on a comprehensive review of BPA's Final EIS 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 final approval, the proposed rate adjustment is scheduled to become effective on October 1, 1982.

2. 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.

a. Revenue Level Alternatives

The EIS examined five basic revenue alternatives: no action; the initial proposal; modification of the proposal to exclude payment of irrigation assistance, extend the amortization period for generation facilities, and exclude recovery of increased shared facility costs resulting from the termination of two nuclear plants under construction by the Washington Public Power Supply System; long run incremental cost (LRIC) pricing; and phased-in LRIC pricing.

Under the no action alternative, BPA would maintain its existing rate structure, resulting in a revenue deficiency of $731 million, given estimated FY 1983 loads contained in the final proposal. Consequently, if this alternative were implemented, BPA would be prohibited from meeting its financial obligations, its statutory requirement to be self-financing would be violated, and the shortfall would have to be recovered from future ratepayers.

Revenues derived under the initial proposal's revenue level alternative would be sufficient to meet BPA's FY 1983 revenue requirement and would represent a 43 percent increase over the estimated revenues that would be collected under current rates during FY 1983. This alternative allows BPA to meet all financial obligations and provides that customers receiving service during FY 1983 would pay the full costs incurred during FY 1983 to provide that service.

Several aspects of BPA's repayment analysis could be modified to reduce BPA's revenue requirements. However, these modifications are either outside BPA's current statutory authority, and thus would require Congressional action in order to be implemented, or would violate current contractual agreements. One way the repayment analysis could be modified would be to eliminate irrigation assistance from BPA's revenue requirement. The effect, however, would be so small that the total revenue requirement for FY 1983 would be virtually unaffected. BPA's repayment process also could be modified by extending the amortization period for generation facilities, thereby reducing the proposed increase in the revenue by approximately 2 percent. Finally, if shared costs of Supply System plants 4 and 5 were excluded from the budgets for plants 1 and 3, BPA's revenue requirement for FY 1983 would decrease by approximately 3 percent.

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 1982 TDLRIC Analysis if applied to BPA's projected FY 1983 sales volume would produce revenues of approximately $5.7 billion. These revenues would be approximately 250 percent higher than revenues recovered under the no action revenue alternative and 133 percent higher than revenues received under the proposed alternative.

One method of easing the impact of shifting to LRIC pricing would be to phase in the LRIC rates over a 5-year period. One-fifth of the difference between rates based on the proposed rate level and rates based on the 1982 TDLRIC Analysis could be added to the proposed rate each year for 5 years. Rates designed in this manner and applied to BPA's projected FY 1983 sales volume would recover revenues of approximately $3.1 billion. This would represent an increase of 90 percent over revenues recovered under the no action alternative and 27 percent over revenues collected under the proposed alternative.

Both the revenue level based on LRIC pricing and that based on graduated LRIC would violate 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 revenues should be distributed or invested.

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 (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, socioeconomic impacts would be expected to increase directly with the price of electricity (revenue level). The level of revenue produced by rates based on marginal cost, for example, could have substantial adverse economic impacts on virtually all regional power consumers, particularly irrigators and low income residential consumers. However, BPA's October 1, 1982, rate proposal is not expected to have serious economic consequences for the Region's electricity consumers (EIS Chapter V(B)(3)).

It is my conclusion after reviewing all pertinent information that the 58 percent revenue increase I am proposing is the least harmful from an environmental standpoint. The 58 percent revenue increase is based on the load forecast in the final proposal which is substantially, less than the load forecast in the initial proposal. 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. I believe that the socioeconomic effects of my proposal are within reason and would not result in undue hardship for BPA's customers. I recognize that, on the one hand, the impacts of this proposed 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, a strain on lower income groups to stay within their budgets, and a somewhat reduced rate of growth within the region of irrigated agriculture. The proposed revenue increase also will enable BPA to conform to its statutory guidelines for meeting repayment requirements and to ensure the prudent operation of the FCRPS.

b. Rate Design Alternatives

I considered the environmental effects of several potentially feasible rate design alternatives in arriving at my decision on the design of specific rate schedules. These schedules included those applicable to the sale of priority firm power, industrial and modified firm power, new resources firm power, nonfirm energy, and firm capacity. I did not consider alternatives to the other rate shedules because I do not anticipate that revenues from sales under these rates or associated environmental effects will be significant.

I am proposing a uniform demand/energy rate structure for the priority firm rate with a daily and seasonal differential in the demand charge and a seasonal differential in the energy charge. The alternatives considered for the proposed structure of the priority firm rate include tiered rates and rates based on the inverse elasticity principle. Tiered rates involve application of different rates to specific blocks of consumption. Under the inverse elasticity approach, customers most responsive to an increase in the cost of electricity would be charged rates closer to incremental costs than those rates charged to less elastic customers. I chose to exclude tiered rates from the rate proposal because of unresolved concerns about their effects on BPA revenue stability, the potential that they might unnecessarily duplicate the function of BPA's billing credit program, and variations they might produce in customer power costs. I rejected basing rates on the inverse elasticity principle because of the lack of reliable elasticity estimates for BPA's customer classes.

The industrial firm power rate schedule that I am proposing reflects a value of reserves credit recognizing the value of the reserves provided by BPA rights to interrupt direct-service industry (DSI) loads. Alternatives I considered and rejected included eliminating the credit, providing a different amount of credit, applying the credit in a different manner or tiering the rates. BPA conducted an extensive study to evaluate the reserves offered by DSI's. Alternative methods considered for applying the reserve credit or tiering the rates could create revenue stability problems. Elimination of the credit would violate the requirements of the Regional Act.

The new resources rate that I am proposing would be based on the cost of exchange resources. An alternative to the proposed rate would be a rate similar to the existing rate that is based on an averaging of the power costs of all new resources acquired by BPA. However, such a rate may cause this power to be unmarketable. No purchases have been made under the existing rate, as no IOU's in the Pacific Northwest have signed the offered power sales contracts which would allow them to purchase power at the new resources rate. A second alternative would be to include two levelized rates in the rate schedule, the first based on lowest cost new resources and the second based on BPA's most costly new resources, the output of which would be marketed as surplus power. This alternative was rejected because sales under the first level would underrecover the average cost of new resources, and power marketed under the second level would be so expensive it would be unmarketable.

The nonfirm rate schedule I am proposing consists of (1) a standard rate in effect at all times, except when a spill or imminent spill condition exists; (2) a spill rate; and (3) an incremental rate applied when the incremental cost of power produced or purchased concurrently with the nonfirm sale is greater than the standard rate. Alternative nonfirm rate schedules considered include a schedule similar to the existing schedule that reflects costs of resources used to produce Federal nonfirm energy, a share-the-savings rate similar to BPA's 1979 nonfirm energy rate, and a flat rate. The proposed rate was selected because it appears to be more acceptable to customers than the current rate, easier to administer than the share-the-savings rate, and more flexible in responding to water and market conditions than the flat rate. If the flat rate were set too high it could discourage purchases of nonfirm energy, resulting in less displacement of thermal resources and increased air and water pollution levels.

I am proposing a firm capacity rate that includes a provision for an additional monthly charge if capacity use exceeds 9 hours per day. In addition to the firm capacity rate I am proposing, I considered a firm capacity rate with no additional monthly charge for capacity use in excess of 9 hours per day and a time-differentiated firm capacity rate. The elimination of the excess capacity charge could result in the need for additional facilities to provide peaking capacity and associated negative physical and socioeconomic environmental impacts. The time-differentiated alternative would have approximately the same effect on the demand for capacity as the proposed rate, but would involve a greater level of administrative complexity.

3. Decision Factors: I based my 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 FCRPS. 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." The Transmission System Act placed BPA on a self-financing basis, requiring it to pay all operating expenses with revenues collected from its rates.

The Pacific Northwest 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.

b. Rate Design Objectives

In addition to meeting legal requirements, BPA rates are designed to meet its revenue requirement while distributing the burden in an equitable manner among recipients of the service, encourage conservation and minimize environmental impacts, and 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 1982 proposed revenue level would reduce regional load requirements from that expected if rates were not increased. Over time, decreases in electricity load growth would limit the regional need for new generation resources equal to three 500 megawatt coal plants and one 1000 megawatt nuclear plant. Elimination of the new generation would avoid accompanying land use, solid waste, water, and air quality impacts associated with mining, processing, and power production. These avoided environmental effects would be somewhat offset by physical enviromental effects resulting from increases in use of alternative energy sources.

The socioeconomic impacts of the revenue level I am proposing for recovery during FY 1983 would be significant for certain types of consumers. Low-income consumers would be more seriously affected by an increase in electricity rates than other residential consumers; the mental, physical, and economic well-being of the low-income elderly could be strained. The proposal could cause DSI's or other energy intensive industrial consumers to hasten decisions to either improve plant efficiency or shut down operations entirely. Some farmers could be forced to go out of business and some acreage could revert to dryland agriculture or be taken out of production. A decrease in irrigated acreage and DSI operations, while creating economic hardships for those employed in these areas, may produce certain benefits to the physical environment.

The proposed rate design alternatives would not cause environmental impacts significantly different than those experienced under BPA's current rate design.

C. Mitigation

Existing and proposed conservation programs offered by BPA could mitigate socioeconomic impacts of the proposed rate increase. BPA offered in FY 1981 and FY 1982 and is planning to offer in FY 1983 energy conservation programs through its utility customers to residential, irrigation, business, and industrial consumers. The 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, lighting, and water heating.

BPA also is implementing or plans to implement energy conservation programs for other consumers in the Pacific Northwest. These include technical assistance to State and local governments, energy conservation audits and installation of conservation measures in institutional buildings, and efficiency improvements for the transmission and distribution systems of regional utilities.

No monitoring or enforcement programs are applicable for mitigation of the adverse impacts of the proposed action and none have been adopted. However, 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 and to provide for environmental quality. BPA's proposed increase includes the cost of implementing these requirements.

IX. Summary of Conclusions

A. The proposed rate schedules have been designed to encourage the widest possible diversified use of electric energy, consistent with other 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 Repayment Study, COSA and TDLRIC Analysis. The proposed rates reflect the results of these studies, but have also 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 Repayment 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 Repayment 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 Repayment 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.

Based upon the foregoing, I hereby adopt as Bonneville Power Administration's final rate proposal the attached wholesale power rate schedules PF-2, IP-2 (MP-2), CF-2, CE-2, NR-2, NF-2, RP-2, FE-2, SI-2, SP-1, SE-1, and EB-1.

Issued at Portland, Oregon this 12th day of August, 1982.

Peter T. Johnson

Peter T. Johnson
Administrator

EXHIBIT A

WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

SCHEDULE PF-2 - PRIORITY FIRM POWER RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest either for resale or for direct consumption by public bodies, cooperatives, Federal agencies, as well as investor-owned utilities and public bodies and cooperatives participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). This schedule supersedes Schedule PF-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(3) all other hours: No demand charge.

b. Energy Charge:

(1) for the billing months September through March: 12.4 mills per kilowatthour of billing energy.

(2) for the billing months April through August: 11.8 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule and the purchasers to whom the factors apply are detailed in parts (a), (b), (c), and (d) of this section.

a. Purchasers taking power under this rate who are not covered by subsections 3(b), 3(c), or 3(d) of this schedule shall be billed on the following fators:

(1) the contract demand as specified in the contract;
(2) the measured demand for the billing month adjusted for power factor;
(3) the measured energy for the billing month.

b. Purchasers designated by BPA to purchase on a computed requirements basis shall be billed in accordance with the provisions of this subsection. A purchaser will be so designated if it has one or more potential abilities as described in paragraphs (i) and (ii) below, unless its power sales contract was executed after December 5, 1980, and provides otherwise:

(i) 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,
(ii) 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 subsection.

Billing factors for designated computed demand customers will be:

3 (1) the peak computed demand for the billing month;
(2) the average energy computed demand for the billing month;
(3) the lesser of the peak computed demand for the month or 60 percent of the highest peak computed demand during the previous 11 billing months;
(4) the measured demand for the billing month adjusted for power factor;
(5) the measured energy for the billing month;
(6) the contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. Purchasers contractually limited to an allocation of capacity and/or energy as determined by BPA pursuant to the terms of a purchaser's power sales contract shall be billed on the following factors:

(1) the allocated demand for the billing month, as specified in the contract;
(2) the measured demand for the billing month adjusted for power factor;
(3) the allocated energy for the billing month, as specified in the contract;
(4) the measured energy for the billing month.

d. Purchasers participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act shall be billed on the following factors:

(1) effective July 1, 1982, seventy percent of the energy associated with the utility's residential load for each billing period. The percentage will be increased by ten percentage points each July 1 until 1985 as specified in the contract;

(2) the demand calculated by applying the load factor, determined as specified in the contract, to the energy in 2(d)(1) for each billing period.

SECTION 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

(1) the billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as BPA determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).
(2) the billing energy for the month shall be factor 3a(3) except that at such time as BPA determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) the billing demand for the month shall be 3b(6) if applicable. Otherwise, it shall be the larger of factors 3b(3) and 3b(4). Factor 3b(4), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(6) if applicable, except that at such time as BPA determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).
(2) the billing energy for the month shall be factor 3b(5) except that at such time as BPA determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3). Factor 3b(5) shall not exceed factor 3b(2) times the number of hours during the month.

c. For a purchaser governed by subsection 3(d):

(1) the billing demand for the month shall be factor 3(d)(2).
(2) the billing energy for the month shall be factor 3(d)(1).

SECTION 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 a purchaser, either at a point of delivery or for a system, at any time that the average power factor for all classes of power delivered to that purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Low-Density Discount: A predetermined discount will be applied each month of a calendar year to the charges for power purchased under contracts between BPA and its eligible customers. The amount of such discount is based on the ratio of the total annual energy requirements of the purchaser's electric operations during the preceding calendar year to the purchaser's depreciated investment in electric plant in service (excluding generating plant) at the end of such year, or the purchaser's ratio of residential consumers to the number of pole miles of distribution line. The calculation of such ratio will be made using the customer's entire utility system within the region. The discount will be granted, however, only when the customer can insure that the consumers within the region will receive the benefits of the discount. If the purchaser has more than 10 residential consumers per mile of line, no discount will apply. Otherwise the discount shall be:

(1) Seven percent if such ratio is less than 15 kilowatthours per dollar of net investment or if the number of consumers per mile of line is two or less.
(2) Five percent if such ratio is equal to or greater than 15 and less than 25 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is four or less.
(3) Three percent if such ratio is equal to or greater than 25 and less than 35 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is six or less.

c. Exchange Adjustment: To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

$$.045 \quad X \quad \frac{28.0 - AC}{28.0} \quad X \quad \text{Bill} \quad X \quad \left(1 + \frac{INT}{2}\right);$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 Cost of Service Analysis (COSA) prepared for the BPA wholesale power rate filing, not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements);

Bill = Total dollar amount charged the customer for service during FY 1983 under this rate schedule; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for purchases under this rate schedule if:

$$.045 \quad X \quad \frac{28.0 - AC}{28.0} \quad \text{is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983, as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments occurring after October 1, 1984.

SECTION 6. Unauthorized Increase:

That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. 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 (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the PF-2 rate is 94.4 percent FBS; 5.6 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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-2 (MP-2) - INDUSTRIAL FIRM POWER RATE

SECTION 1. 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 schedule is also available to existing direct-service industrial customers for the purchase of modified firm power on a contract demand basis for direct consumption by any existing direct-service industrial customer with a Modified Firm power sales contract; provided that in the event such a customer receives service under his Modified Firm power sales contract, no value of reserves adjustment will be made. This rate schedule supersedes Schedules IP-1 and MP-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

For periods when the purchaser has not requested service to the first quartile with surplus Firm Energy Load Carrying Capability (FELCC), the following rate applies:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(3) all other hours: No demand charge.

b. Energy charge:

(1) for the billing months September through March: 24.8 mills per kilowatthour of billing energy.
(2) for the billing months April through August: 22.8 mills per kilowatthour of billing energy.

For periods when the purchaser has requested service to the first quartile with surplus FELCC, the following rate applies:

c. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(3) all other hours: No demand charge.

d. Energy charge:

(1) for the billing months September through March: 27.8 mills per kilowatthour of billing energy.
(2) for the billing months April through August: 25.6 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. operating demand
b. curtailed demand
c. restricted demand
d. auxiliary demand
e. measured energy

SECTION 4. Determination of Billing Demand and Billing Energy:

The billing demand for industrial firm power will be the lowest of the respective operating demand, curtailed demand, or restricted demand after such demand is adjusted for power factor. The billing demand for auxiliary power requested by the purchaser and made available by BPA will be the demand for auxiliary power as adjusted for power factor. During any billing month in which there is more than one demand for industrial firm power or auxiliary power, the billing demand for the month will be the weighted average for the billing month of the billing demands. If the purchaser requests auxiliary power during the billing month, the billing demand for auxiliary power will be the weighted average of the billing demands for the number of days during the billing month in which the purchaser received auxiliary power. The billing energy associated with each of the respective billing demands will be the measured energy distributed among the respective billing demands for each period such billing demand is applicable during the billing month.

SECTION 5. Adjustments:

a. Value of Reserves: A monthly billing credit for the value of the reserves provided by purchasers of industrial firm power shall be:

(1) $1.31 per kilowatt of billing demand.
(2) 0.4 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 this rate schedule. The value of reserves adjustment is not applicable to customers purchasing modified firm power.

b. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the billing demand for the month by 1 percent for each 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

c. Exchange Adjustment: To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

$$.920 \times \frac{28.0 - AC}{28.0} \times \text{Bill} \times \left(1 + \frac{INT}{2}\right);$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 COSA prepared for the BPA wholesale power rate filing, not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements);

Bill = Total dollar amount charged the customer for service during FY 1983 under this rate schedule; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for purchases under this rate schedule if:

$$.920 \times \frac{28.0 - AC}{28.0} \text{ is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983, as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to

October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 6. Unauthorized Increase:

The amount by which any 60-minute clock-hour integrated demand exceeds the sum of (1) the billing demand during that hour before adjustment for power factor and (2) any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the IP-2 rate is 1.0 percent FBS and 99.0 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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 SI-2 - SPECIAL INDUSTRIAL POWER RATE

SECTION 1. 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 (Regional Act).

SECTION 2. Rate:

a. Demand Charge:

(1) For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(2) For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(3) All other hours: No demand charge.

b. Energy Charge:

(1) for the billing months September through March: 12.4 mills per kilowatthour of billing energy.
(2) for the billing months April through August: 11.8 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. operating demand
b. curtailed demand
c. restricted demand
d. auxiliary demand
e. measured energy

SECTION 4. Determination of Billing Demand and Billing Energy:

The billing demand for this special class of industrial power will be the lowest of the respective operating demand, curtailed demand, or restricted demand after such demand is adjusted for power factor. The billing demand for auxiliary power requested by the purchaser and made available by BPA will be the demand for auxiliary power as adjusted for power factor. During any billing month in which there is more than one demand for industrial firm power or auxiliary power, the billing demand for the month will be the weighted average for the billing month of the billing demands. If the purchaser requests auxiliary power during the billing month, the billing demand for auxiliary power will be the weighted average of the billing demands for the number of days during the billing month in which the purchaser received auxiliary power. The billing energy associated with each of the respective billing demands will be the measured energy distributed among the respective billing demands for each period such billing demand is applicable during the billing month.

SECTION 5. Adjustments:

a. Value of Reserves: An adjustment for the value of the reserves provided by purchasers of this special class of industrial power shall be:

(1) $1.31 per kilowatt of billing demand.
(2) 0.4 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 this rate schedule.

b. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the billing demand for the month by 1 percent for each 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 75 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

SECTION 6. Unauthorized Increase:

The amount by which any 60-minute clock-hour integrated demand exceeds the sum of (a) the billing demand during that hour before adjustment for power factor and (b) any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The SI-2 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 9. 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 Consevation Act.

SCHEDULE CF-2 - FIRM CAPACITY RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of firm capacity without energy on a contract demand basis for supply during a contract year of 12 months or during a contract season of 5 months, June 1 through October 31. This schedule supersedes Schedule CF-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Contract Year Service: $36.72 per kilowatt per year of contract demand, billed monthly at the rate of $3.06 per kilowatt of contract demand.

b. Contract Season Service: $13.30 per kilowatt per season of contract demand, billed monthly during the contract season at the rate of $2.66 per kilowatt of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by $.024 per kilowattmonth of billing demand per hour that the purchaser's monthly demand duration exceeds nine (9) hours. The purchaser's demand duration for the month shall be determined by dividing the kilowatthours supplied under this rate schedule to a purchaser on the day of maximum kilowatthour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand for such month. During periods when BPA does not require the delivery of peaking replacement energy by the purchaser, the additional charge described above will not be applied.

SECTION 3. Billing Factors:

The billing demand will be the contract demand.

SECTION 4. Special Provision:

Contracts for the purchase of firm capacity under this schedule will include provisions for replacement by the purchaser of energy accompanying the delivery of such capacity.

SECTION 5. Exchange Adjustment:

To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for annual capacity customers will be equal to:

$$.053 \quad X \quad \frac{28.0 - AC}{28.0} \quad X \quad \text{Bill} \quad X \quad \left(1 + \frac{INT}{2}\right);$$

For seasonal capacity customers the rebate will be:

$$.012 \quad X \quad \frac{28.0 - AC}{28.0} \quad X \text{ Bill } X \left(1 + \frac{INT}{2} \right);$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 COSA prepared for the BPA wholesale power rate filing, not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements);

Bill = Total dollar amount charged the customer for service during FY 1983 under this rate schedule; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for annual capacity customers under this rate schedule if:

$$.053 \quad X \quad \frac{28.0 - AC}{28.0} \quad \text{is less than } .001.$$

No rebate will be given for seasonal capacity customers under this rate schedule if:

$$.012 \quad X \quad \frac{28.0 - AC}{28.0} \quad \text{is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983 as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 6. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the CF-2 rate is 92.7 percent FBS and 7.3 percent Exchange for annual service, and 100 percent FBS for seasonal service.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 7. 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-2 - EMERGENCY CAPACITY RATE

SECTION 1. Availability:

This schedule is available for purchase of emergency capacity requested by a purchaser when BPA determines that an emergency condition exists on the purchaser's system and it has capacity available for such purpose. This schedule supersedes Schedule CE-1 which went into effect on an interim basis on July 1,1981.

SECTION 2. Rate:

$0.81 per kilowatt of demand per calendar week or portion thereof. For deliveries over the Pacific Northwest-Pacific Southwest Intertie, made available for the account of a purchaser at the Oregon-California or the Oregon-Nevada border, the charge will be increased by $0.19 per kilowatt per week. Bills will be rendered monthly.

SECTION 3. Billing Factors:

The billing demand will be the maximum amount requested by the purchaser and made available by BPA during a calendar week, provided that if BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, such billing demand for such week shall be the lower demand which BPA is able to supply.

SECTION 4. Special Provision:

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery at times and rates of delivery agreed to by the purchaser and BPA prior to delivery. BPA may agree to accept delay of return energy beyond 7 days if it so agrees prior to the delivery of capacity.

SECTION 5. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the CE-2 rate is 92.7 percent FBS; 7.3 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 6. 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 FE-2 - FIRM ENERGY RATE

SECTION 1. Availability:

This schedule is available to purchasers with contracts in effect prior to October 1, 1982, which refer to this rate schedule or its predecessor, for purchase of firm energy, to be delivered for the uses, in the amounts, and during the period or periods specified in such contract. This schedule supersedes Schedule FE-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

16.4 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The contract energy is the billing factor.

SECTION 4. Determination of Billing Energy:

The billing energy shall be determined as provided in the purchaser's power sales contract.

SECTION 5. Delivery:

Delivery of energy under this rate schedule is assured during the contract period. However, BPA may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that BPA determines that BPA is unable because of system operating conditions, including lack of generation or transmission capacity, to effect such delivery.

SECTION 6. Power Factor Adjustment:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the FE-2 rate is 94.4 percent FBS; 5.6 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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-2 - NEW RESOURCE FIRM POWER RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of firm power for resale or for direct consumption by investor owned utilities in the Pacific Northwest under net requirement contracts and by any public body, cooperative or Federal agency to the extent 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). This schedule supersedes Schedule NR-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(3) all other hours: No demand charge.

b. Energy Charge:

(1) for the billing months September through March: 26.7 mills per kilowatthour
(2) for the billing months April through August: 24.5 mills per kilowatthour

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule and the purchasers to whom the factors apply are detailed in parts (a), (b), and (c) of this section.

a. Purchasers taking power under this rate who are not covered by subsections 3(b), or 3(c) of this schedule shall be billed on the following fators:

(1) the contract demand as specified in the contract;
(2) the measured demand for the billing month adjusted for power factor;
(3) the measured energy for the billing month.

b. Purchasers designated by BPA to purchase on a computed requirements basis shall be billed in accordance with the provisions of this subsection. A purchaser will be so designated if it has one or more potential abilities as described in paragraphs (i) and (ii) below, unless its power sales contract was executed after December 5, 1980, and provides otherwise:

(i) 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,

(ii) Such purchaser has the ability to redistribute generation from its resources over time and 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 subsection.

(1) the peak computed demand for the billing month;
(2) the average energy computed demand for the billing month;
(3) the lesser of the peak computed demand for the month or 60 percent of the highest peak computed demand during the previous 11 billing months;
(4) the measured demand for the billing month adjusted for power factor;
(5) the measured energy for the billing month;
(6) the contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. Purchasers contractually limited to an allocation of capacity and/or energy as determined by BPA pursuant to the terms of a purchaser's power sales contract shall be billed on the following factors:

(1) the allocated demand for the billing month, as specified in the contract;
(2) the measured demand for the billing month adjusted for power factor;
(3) the allocated energy for the billing month, as specified in the contract;
(4) the measured energy for the billing month.

SECTION 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

(1) the billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as BPA determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).
(2) the billing energy for the month shall be factor 3a(3) except that at such time as BPA determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) the billing demand for the month shall be 3b(6) if applicable. Otherwise, it shall be the larger of factors 3b(3) and 3b(4). Factor 3b(4), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(6) if applicable, except that at such time as BPA determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) the billing energy for the month shall be factor 3b(5) except that at such time as BPA determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3). Factor 3b(5) shall not exceed factor 3b(2) times the number of hours during such month.

SECTION 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Exchange Adjustment: To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

$$.882 \quad X \quad \frac{28.0 \; - \; AC}{28.0} \quad X \quad \text{Bill} \quad X \quad (\; 1 + \frac{INT}{2} \;)$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 COSA prepared for the BPA wholesale power rate filing, not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements);

Bill = Total dollar amount charged the customer for service during FY 1983 under this rate schedule; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for purchases under this rate schedule if:

$$.882 \quad X \quad \frac{28.0 - AC}{28.0} \quad \text{is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983 as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 6. Unauthorized Increase:

That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. 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 (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the NR-2 rate is 100 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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-1 - SURPLUS FIRM POWER RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of surplus firm power both inside and outside the Pacific Northwest, as well as outside the United States, for resale or for direct consumption by purchasers other than direct-service industrial purchasers who purchase power under rate schedule IP-2 (MP-2).

SECTION 2. Rate:

a. For service with exchange resources, Centralia, Weyerhaeuser and Longview Fibre, Idaho Falls, and Felt:

(1) Demand Charge:

(a) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(b) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(c) all other hours: No demand charge.

(2) Energy Charge:

28.4 mills per kilowatthour of billing energy.

b. For service with a specific discretionary resource or resources not included in subsection a:

(1) Demand Charge:

(a) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $4.21 per kilowatt of billing demand.
(b) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.91 per kilowatt of billing demand.
(c) All other hours: No demand charge.

(2) Energy Charge:

(a) $$\frac{AC - DR}{AO} + \text{Adder}$$

Where: AC = Annual cost of resource(s)
DR = Annual revenue from demand charge
AO = Annual output of resource in kilowatthours
Adder = 6.4 mills per kilowatthour

AC, AO, and DR shall be calculated on a prospective basis and agreed to by BPA and the purchaser.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. the contract demand as specified in the contract;
b. the measured demand for the billing month adjusted for power factor;
c. the contract amount of energy for the month;
d. the measured energy for the month.

SECTION 4. Determination of Billing Demand and Billing Energy:

The billing demand and billing energy shall be determined as provided in a purchaser's contract. If BPA does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

SECTION 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

   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 a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Exchange: To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

$$.642 \quad X \quad \frac{28.0 \; - \; AC}{28.0} \quad X \quad Bill \quad X \quad \left(1 + \frac{INT}{2} \right);$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 COSA prepared for the BPA wholesale power rate filing not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements);

Bill = Total dollar amount charged the customer under Section 2(a) for service under this rate schedule during FY 1983; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for purchases under this rate schedule if:

$$.642 \quad X \quad \frac{28.0 - AC}{28.0} \text{ is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983, as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 6. Unauthorized Increase:

That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. 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 (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the SP-1 rate is 72.6 percent Exchange and 27.4 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available nonfirm energy.

SECTION 8. 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-1 - SURPLUS FIRM ENERGY RATE

SECTION 1. Availability:

This schedule is available for the purchase of surplus firm energy for resale or for direct consumption by purchasers other than direct-service industrial purchasers who purchase power under rate schedule IP-2 (MP-2). It is also available for purchase of surplus firm energy by entities outside the United States.

SECTION 2 Rate:

28.4 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate are as follows:

a. The contract amount of energy for the month;
b. The measured energy for the month.

SECTION 4. Determination of Billing Energy:

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 5. Delivery:

Delivery of energy under this rate schedule is assured during the contract period. However, BPA may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that BPA determines that BPA is unable to effect such delivery because of system operating conditions, including lack of generation or transmission capacity.

SECTION 6. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

   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 purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Exchange Adjustment: To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0 mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

$$.642 \quad X \quad \frac{28.0 \ - \ AC}{28.0} \quad X \ \text{Bill} \ X \ \left(1 + \frac{INT}{2} \right);$$

where: AC = Average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired during FY 1983 from the utilities listed in Table A-1 of the August 1982 COSA prepared for the BPA wholesale power rate filing, not including interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase Sale Agreements); and

Bill = Total dollar amount charged the customer for service during FY 1983 under this rate schedule; and

INT = The average rate of interest charged BPA by the U.S. Treasury during FY 1983.

No rebate will be given for purchases under this rate schedule if:

$$.642 \quad X \quad \frac{28.0 \ - \ AC}{28.0} \quad \text{is less than } .001.$$

No surcharge will be levied if AC as defined above is greater than 28.0 mills per kilowatthour. Payment of the rebate will be made as soon after October 1, 1983 as the necessary calculations can be made. The rebate shall be subject to adjustment upward or downward after October 1, 1984, if the Joint State Board, the FERC, a reviewing court, or BPA makes any adjustment prior to October 1, 1984, which changes AC as defined above from that used initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the SE-1 rate is 72.6 percent Exchange and 27.4 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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-2 - NONFIRM ENERGY RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of nonfirm energy both inside and outside the Pacific Northwest and outside the United States. This schedule is also available for energy delivered for emergency use under the conditions set forth in Section 4.1 of the General Rate Schedule Provisions. This schedule is not available for the purchase of energy which BPA has a firm obligation to supply. This schedule supersedes Schedule NF-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Nonfirm Energy Rate: The price per kilowatthour of billing energy will be set according to the following three conditions. More than one condition may apply at any given time.

(1) Standard Rate: This rate shall apply when the Federal Columbia River Power System (FCRPS) hydroelectric plants are not in a spill or imminent spill condition due to an excess of energy on the FCRPS above available markets. The rate shall be 18.2 mills per kilowatthour. At the time BPA offers nonfirm energy under this rate, BPA will indicate the maximum amount of energy available for the next day or days over which nonfirm is normally prescheduled in the Pacific Northwest and the maximum hourly rates at which such energy is available. BPA shall offer 50 percent of the maximum amount of energy and 50 percent of each maximum hourly amount on a guaranteed delivery basis. At the time the purchaser arranges schedules of such energy, it shall indicate the amount it wishes to schedule on a guaranteed delivery basis and the amount it wishes to schedule on a nonguaranteed delivery basis. The energy BPA makes available under this rate for delivery the same day is not subject to the guaranteed delivery provision. BPA shall offer nonfirm energy for sale under this standard rate and the purchaser shall schedule the delivery of such energy in accordance with the scheduling provisions of the purchaser's power sale agreement with BPA. To the extent BPA offers and the purchaser schedules delivery on a guaranteed delivery basis, scheduled amounts may not be changed except when:

(a) BPA and the Purchaser mutually agree to increase or decrease the scheduled amounts, or
(b) BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation loss in the Pacific Northwest.

(2) Spill Rate: When a spill or imminent spill condition exists at one or more FCRPS hydroelectric plants due to an excess of energy on the FCRPS above available markets, the rate shall be 9.0 mills per kilowatthour.

(3) Incremental Rate: For power (a) which is produced or purchased concurrently with the nonfirm sale, (b) which BPA may at its option not produce or purchase, and (c) whose incremental cost is greater than 16.2 mills per kilowatthour; the rate shall be equal to the incremental cost of that power plus 2.0 mills per kilowatthour. Incremental cost is defined as all identifiable costs 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 11.2 mills per kilowatthour.

SECTION 3. Delivery:

BPA shall determine the availability of energy hereunder and the rate of delivery thereof.

SECTION 4. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the NF-2 standard rate is 96.7 percent FBS and 3.3 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 5. General Provisions:

Sales of energy 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-1 - ENERGY BROKER RATE

SECTION 1. Availability:

This schedule is available for both the sale and purchase of nonfirm power among participants in the Western Systems Coordinating Council (WSCC) Energy Broker System, between whom agreements for energy transmission have been transacted. This schedule will only be used when sales cannot be made under other schedules.

SECTION 2. Rate:

When a transaction takes place on the Energy Broker System, the buy price and sell price, respectively, will 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 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.

The following formula will be used in determining the rate at which power will be sold, or nonfirm power purchased on the energy broker:

$$\text{EB-1} = \frac{BP + SP}{2}$$

Where: EB-1 = 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 2 mills per kilowatthour less than the buy price. The final transaction rate for brokered nonfirm energy will be based on splitting the difference between 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.

SECTION 3. Delivery:

BPA shall determine the availability of energy hereunder and the rate of delivery thereof.

SECTION 4. Resource Cost Contribution:

The cost contribution of different resource categories to the EB-1 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 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 5. 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-2 - RESERVE POWER RATE

SECTION 1. 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; 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 applicable. It is also available for purchase of power by entities outside the United States. This rate schedule supersedes Schedule RP-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $8.35 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $4.17 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge: 42.3 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. the contract demand as specified in the contract;
b. the measured demand;
c. the contract amount of energy for the month;
d. the measured energy for the month.

SECTION 4. Determination of Billing Demand and Billing Energy:

The billing demand and billing energy shall be determined as provided in a purchaser's power sales contract. If BPA does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

SECTION 5. Power Factor Adjustment:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand 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 is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

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 a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 6. Unauthorized Increase:

That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. 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 (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

The RP-2 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 16.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 8. 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.

GENERAL RATE SCHEDULE PROVISIONS

SECTION 1.1. Priority and New Resource Firm Power:

Priority and new resource firm power is electric power which BPA will make continuously available to a purchaser to meet its actual firm load requirements within the Pacific Northwest except when restricted because the operation of generation or transmission facilities used by BPA to service such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of priority and new resource firm power shall not be made until industrial firm power has been restricted in accordance with Section 1.4 and until modified firm power has been restricted in accordance with Section 1.2. The New Resource Firm Power rate is applicable to any increase in energy consumption of a load as defined in section 3(13) of the Pacific Northwest Electric Power Planning and Conservation Act or, when applicable, section 8 of the final utility power sales contract offered August 28, 1981 as published in the Notice of Final Action Concerning Power Sales and Residential Exchange Contracts Required by Pacific Northwest Electric Power Planning and Conservation Act (46 FR 44353) September 3, 1981.

SECTION 1.2. Modified Firm Power:

Modified firm power is electric power which BPA will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to priority and new resource firm power, and (b) the following:

When a restriction is made necessary because the operation of generation or transmission facilities used by BPA to serve a modified firm power purchaser and any priority or new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, BPA shall restrict such purchaser's Contract Demand for Modified Firm Power to the extent necessary to prevent, if possible, or minimize restriction of any priority and new resource firm power, provided, however that:

(1) such restriction of modified firm power shall not exceed at any time 25 percent of the contract demand therefore, and
(2) the accumulation of such restrictions of modified firm power during any calendar year, expressed in kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The

extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

SECTION 1.3. Firm Capacity:

Firm capacity means capacity which BPA assures will be available to a purchaser in amounts and during the periods specified in the contract except when operation of the generation or transmission facilities used by BPA to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 1.4. Industrial Firm Power:

Industrial firm power is electric power which BPA will make continuously available to a purchaser on a Contract Demand Basis subject to: (a) 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 contract, and (b) the following:

(1) the restrictions given in the Restriction of Deliveries Section of the contract.

(2) when a restriction is made necessary because of the operation of the generation or transmission facilities used by BPA to serve an industrial firm power purchaser, and any priority or new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, BPA shall restrict such purchaser's Operating Demand for Industrial Firm Power to the extent necessary to prevent, if possible, or minimize restriction of priority and new resource firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract and operating demands bear to one another. The extent of such restrictions shall be limited for modified firm power by Section 1.2(b) of these General Rate Schedule Provisions and for industrial firm power by the Restrictions of Deliveries Section of the contract.

SECTION 1.5. Authorized Increase:

An authorized increase is an amount of electric power specified in the contract in excess of the contract or operating demand for priority firm power, new resource firm power, modified firm power, industrial firm power as sold under the interim firm contract, or that BPA may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. BPA will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

SECTION 1.6. Firm Energy:

Firm energy is energy which BPA assures will be available to a purchaser during the period or periods specified in the contract except during hours as may be specified in the contact and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 2.1. Contract Demand:

The contract demand shall be the number of kilowatts that the purchaser 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 (authorized increase), but shall not be obligated to continue such excess deliveries.

SECTION 2.2. Auxiliary Demand:

Auxiliary demand is the number of kilowatts in excess of operating demand that a direct service industrial purchaser requests and that BPA is able to make available to serve that purchaser's load. After the purchaser makes such a request, BPA will determine whether such demand can be made available. BPA shall retain the right to restrict the delivery of energy to supply such auxiliary power demand if it determines at any subsequent time that auxiliary power is no longer available. The purchaser may curtail deliveries of auxiliary power by written notice to BPA given at least 24 hours prior to the first day of any month.

SECTION 2.3. Measured Demand:

The purchaser's measured demand will be determined according to this section unless the terms of a contract executed after December 5, 1980 provide otherwise. 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 at which electric energy is delivered to a purchaser at each point of delivery 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 contract, or as determined in Section 2.6 herein. 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 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. 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 integrated demand assigned to any class of power shall be determined as specified in the contract. 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 purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal System, the purchaser's measured demand for each class of power for such system for any billing period shall be based on ratchet demand.

SECTION 2.4. Peak Computed Demand and Energy Computed Demand:

The purchaser's peak computed demand and energy computed demand will be determined according to this section unless terms of a contract executed after December 5, 1980 provide otherwise.

The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand 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.

a. General Principles:

(1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.
(2) As used in this section, "year" shall mean the 12-month period commencing July 1.
(3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least requirement for capacity and energy on BPA.
(4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.

(5) Prior to the beginning of each 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 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 with such requirement increasing each year not in excess of the purchaser's annual load growth.

(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 on a firm basis to its load. 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 energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated; and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate 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 storage operation 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 computed demand 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 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 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 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 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 that such change could actually be accomplished, and that the remaining balance of its total critical period assured 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 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 indicated by such revisions in the monthly distribution of critical period energy capability.

(2) <u>Thermal Generating Facilities</u>: The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.

(3) Other Sources of Power: The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. Determination of Computed Demand: The purchaser's computed demand for each billing month shall be the greater of:

(1) The largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or

(2) The largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of priority and new resource firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

SECTION 2.5. Restricted Demand:

A restricted demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when BPA has restricted delivery of such power for one (1) clock-hour or more. Such restrictions by BPA are made pursuant to the power sales contract for industrial firm power and pursuant to Section 1.1 and 1.2 of the General Rate Schedule Provisions for priority and new resource firm power and modified firm power, respectively. Such restricted demand shall be determined by BPA after the purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with Section 2.6 of the General Rate Schedule Provisions.

SECTION 2.6. Curtailed Demand:

A curtailed demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, auxiliary power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the contract. Each purchaser of an authorized increase in excess of priority firm power, new resource firm power, or modified firm power may curtail its demand in accordance with Section 1.5 of the General Rate Schedule Provisions.

SECTION 3.1. Temporary Curtailment of Contract Demand:

The reduction of charges for power curtailed pursuant to the purchaser's contract and Section 1.5 and 2.6 hereof shall be applied in a uniform manner.

SECTION 4.1. Energy Supplies for Emergency Use:

A purchaser taking priority and/or new resource firm power shall pay in accordance with Wholesale Nonfirm Energy Rate Schedule NF-2 and Emergency Capacity Schedule CE-2 for any electric energy or capacity which has been supplied; (a) for use during an emergency on the purchaser's system; or (b) following an emergency to replace energy secured from sources other than BPA during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

SECTION 5.1 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 (a) to bill for service to such new, additional, or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor, or (b) if such facilities are served by a distributor purchasing power therefor from BPA to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor. Any rate schedule provisions regarding contract demand, billing demand, and minimum monthly charge 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.

SECTION 6.1. Billing:

Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when (a) delivery at more than one point is beneficial to BPA, or (b) the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

SECTION 6.2. 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 contract.

SECTION 7.1. Billing Month:

Meters will normally 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 or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. 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.

SECTION 8.1. Payment of Bills:

Bills for power shall be rendered monthly and shall be payable at BPA's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be 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.

If BPA is unable to render the purchaser 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 be subject to the same repayment provisions as shall a final bill.

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 shall be the greater of one-fourth percent (0.25%) of the amount unpaid 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. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

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 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 purchaser, the next following business day shall be 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 must bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

SECTION 9.1. Average Power Factor:

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 include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatthours and reactive kilovoltamperehours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

SECTION 10.1. Approval of Rates:

Schedules of rates and charges, or modifications thereof, for electric power sold by BPA 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.

SECTION 11.1. General Provisions:

The Wholesale Rate Schedules and General Rate Schedule Provisions of BPA which are effective October 1, 1982, supersede in their entirety BPA's Wholesale Power Rate Schedule Provisions effective July 1, 1981. Such schedules and provisions shall be applicable to every BPA contract, including contracts executed prior to and contracts executed subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act.

EXHIBIT B

Rate Pools

The primary concern raised with respect to BPA's interpretation of Sections 7(b), 7(c), and 7(f) of the Regional Act revolves around the issue of the allocation of the cost of the three resource pools to rate pools. The three resource pools are distinguished as (1) Federal base system resources; (2) resources acquired through the Section 5(c) residential exchange; and (3) any additional new resources acquired by the Administrator. Three rate pools are also defined in the Regional Act. Section 7(b) directs the Administrator to set a rate applicable to the preference customer loads exclusive of new large single loads and to Section 5(c) residential/rural exchange loads. Section 7(c) provides for the rate or rates applicable to the DSI's, and the rates provided for in 7(f) will be applicable to new large single loads of the preference customers and the power supply needs (deficit plus load growth) of the IOU's. These are the three essential sections of the Regional Act defining the three rate pools. They also provide the principal basis for the identification of three resource pools.

In the COSA, a sufficient amount of Federal base system resources were assigned to the 7(b) rate pool to serve the entire 7(b) load. The proportionate cost of these resources was the basis for determining the proposed PF-1 rate. A small amount of Federal base system was not required to serve 7(b) loads. The costs of the remaining portion of Federal base system resources, and all the costs of resources acquired through the residential exchange were assigned to be recovered from the 7(c) loads. These costs were the basis for determining the proposed IP-1/MP-1 rate. The 7(f) loads were assigned the costs of all remaining resources which constituted additional new resources. These costs formed the basis for the proposed NR-1 rate.

The InterCompany Pool has expressed concern that assignment of a portion of the Federal base system resources as well as the exchange resources exclusively to the DSI cost pool constitutes the granting of a special junior preference to the DSI's. The InterCompany Pool contends that this is inappropriate and conflicts with both the intent of the Regional Act and its legislative history. The InterCompany Pool has stated that BPA should recognize only two rate pools and three rates. The first of these would be a Regional rate pool which would be assigned the costs of that portion of the Federal base system resources required to meet preference customer and exchange loads, that is, the loads under 7(b). The second rate pool would include all remaining firm loads of the Administrator and would be assigned the costs of all remaining firm resources used to meet this load. This would encompass three quartiles of the DSI load, new large single loads of preference customers, and IOU requirements exclusive of the exchange. This rate pool would provide the base upon which to develop both a new resource rate as well as the rate for the DSI's.

I have reviewd the Regional Act and its legislative history very carefully on this matter because of its significance. I can understand some confusion arising because of the difference in the treatment of the DSI rate before and after July 1, 1985. That difference does impact the rate pool concept. In order to deal effectively with this issue it is necessary to consider the situation after July 1, 1985 as well as the present circumstance. I feel that the method adopted for this year is fully consistent with the situation after July 1, 1985 and is directly consistent with the Regional Act and its intent as indicated through the legislative history.

The identification of the Section 5(c) exchange power as a separate resource pool is dictated by the need to move this resource in both cost and supply, as a means of allocating costs, and as a means of indication that the resource is serving a particular load. This is needed both before and ofter July 1, 1985 and is the only approach we could find that was consistent for both periods.

Before July 1, 1985, the Regional Act clearly identifies three rate pools all based on costs. Section 7(b) is well defined. Section 7(c) gives the Administrator discretion in the determination of the appropriate assignment of resources to serve this rate pool. However, it makes it clear that the DSI's will pick up the costs of the exchange to the extent not recovered in other rates. Section 7(f) also provides direction in the assignment of resources and costs.

I have therefore reviewed extensively the legislative history including all supporting documents, appendices and floor standards. I have also attempted to understand, on the basis of the record, what was understood in the region and, more importantly how the treatment of rate pools fits with the logic of the Regional Act and the period after July 1, 1985. I find the fundamental concept was that for this period, the DSI's are responsible to hold harmless the preference customers from any adverse impact of the Section 5(c) exchange. This is consistent with the Section 7(b) rate test after July 1, 1985, where the DSI's are no longer on a cost based rate. Furthermore, the DSI's are encouraged by the Regional Act to relinquish their existing rights (for the term of contracts existing prior to the Regional Act) to the Federal base system on a gradual basis to provide the rate relief to the Section 5(c) exchanging utilities and, in exchange, pay those costs in order to protect the preference customers. This is the only logic supporting the 60 percent exchange limit in this first year with an increase of 10 percent per year thereafter until July 1, 1985. The net effect of this conclusion is that the DSI's load is met by exchange resources to the lesser of the extent available and the extent they have relinquished Federal base system resources. The Federal base system resources they have not relinquished continue to be used to meet their loads.

The Section 7(f) rate pool would thus contain: first, any Federal base system not needed for 7(b) loads and not relinquished by the DSI's (i.e., once an existing DSI contract expires, that portion of Federal base system is no longer availabe to the DSI's); second, any exchange resources not used by the DSI's to replace their relinquished Federal base system; and lastly, all other resources.

After July 1, 1985 there are fundamentally the two rate pools advocated by the investor-owned utilities, the 7(b) rate pool and the 7(f) rate pool. The Section 7(c) rate is determined independently of cost. The costs of the three resource pools move between the two rate pools in proportion to the amounts needed to satisfy the load size in each rate pool and in accordance with the priorities established in Section 7(b). The 7(b) rate pool is satisfied first with Federal base system, then, as needed, with exchange, and finally with the new resources.

The DSI rate after July 1, 1985 is not based on costs but is independently established by determining a representative markup above wholesale power costs used by the preference customers to set their retail rates to their industrial customers. This representative markup is then applied to BPA's rate to the preference customers for the industrial portion of their load which will be a combination of both 7(b) and 7(f) as appropriate, recognizing new single large industrial loads.

The revenues from this DSI rate is then compared with the cost of resources to serve the DSI load. Any surpluses or shortfalls are then uniformly applied to all other sales. The resources used to serve the DSI load are expected to come from the 7(f) rate pool.

I believe that, for the above reasons, the method of cost assignment I have in these rates is fundamentally correct. This cost allocation method is also supproted by a review of the Regional Act and its legislative history.

The InterCompany Pool relies heavily upon Appendix B of the Senate Report on S. 885 as support for its position. As indicated, and for reasons more fully set forth in BPA Counsel's memorandum, I believe that Appendix B is of dubious value in guiding my distribution of the cost of resources under the Regional Act.

Appendix B, of course, is a numerical analysis based upon certain specified assumptions regarding the overall impacts of rates upon customer classes. It is prefaced by several caveats as to its use, one of which concerns the potential for changed circumstances:

> "In full recognition that as a matter of law under this act rates shall be established pursuant to specific statutory provisions in sections 7 and 9 and that the circumstances which were asumed in preparing this analysis and accompanying narrative in the appendix."
> Senate Report at 32.

Portland General Electric Company in its response brief is very critical of BPA Counsel's position that Appendix B is not a reliable indicator of Congressional intent. I am not convinced by PGE's rebuttal of BPA Counsel's position. I find that Appendix B tends to create an ambiguity when read with the other legislative history as to the assignment to new resources and secondly, the light of the Senate Energy Committee's caveats as to its use and the subsequent change in circumstances (including IOU load growth sales in the early years of the Act) is simply not a reliable indicator of Congressional intent in view of today's circumstances.

The ICP also argues, in the brief of counsel for Puget Sound Power and Light Company, that the express words of 7(c) that the DSI's are to pay the otherwise unrecovered net costs of the exchange "to the extent that such costs are not recovered through rates applicable to other customers" must have some meaning. Puget's conclusion is that it was intended that both the unrecovered net costs of the exchange, and the otherwise unrecovered FBS costs should be shared with the IOU's by melding with more expensive resources (the two cost pools theory) (PSP&L brief at 23). I agree that all words of a statute are presumed to have meaning. In this case, I simply look to the express reservation of the costs of the 5(c) exchange resources to preference and exchange customers under 7(b)(1) of the Regional Act under circumstances in which the FBS is insufficient to serve their loads. Under such a circumstance, the relatively inexpensive exchange resouces would be used to serve the 7(b) loads prior to assigning the more expensive "other (new) resources". Thus, the "other customers" referred to in the quoted passed of 7(c)(1) of the Act refers to 7(b) customers.

At page 25 of its brief, Puget asks the relevant question: "What is the legal authority for such a preference"? Meaning, where is BPA authorized to assign the "left-over" FBS resource costs to the DSI's and the costs of the exchange, without requiring the DSI's to pick up any new resource costs? The answer, of course, is found in the express words of the statute. The Administrator "determines" which resources (and thus which costs) are to be assigned as serving the 7(c) and 7(f) loads. It is true that 7(f) expressly mentions FBS and exchange resources and "additional resources" in listing those from which the Administrator may assign costs. After 1985 it is likely that certain exchange costs (and perhaps some FBS) costs will be assigned to the 7(f) rate if the Administrator determines that such resources serves the 7(f) load. After 1985, of course, the DSI rate is no longer computed upon BPA costs--but rather based upon a comparision with rates of preference customers industrial customers' rates. It is because of this complex and shifting array of costs that I believe Congress delegated me the responsibility of determining where resource costs should be placed.

As indicated by BPA Counsel's analysis of the three committee reports (both narrative analyses and section-by-section analyses) the DSI rate was continually referred to as being based upon the unrecovered net costs of the exchange and the 7(f) rate as being "the marginal cost of power" (House Commerce Report at 51) or "a new resource rate" (House Commerce Report at 69; House Interior Report at 52). Based upon the usual indicators of Congressional intent--the bodies of the Committee reports, I believe that my determinations regarding assignment of resource pool costs is consistent with that intent. Thus, in answer to Puget's inquiry, it is the express words of the statute which give me the obligation and authority to determine costs and it is the legislative history that has guided the manner in which I have done so.

Another issue raised by the InterCompany Pool relates to the potential willingness of utilities to make the output of new resources available to the Administrator. It was suggested that by assigning the costs of conservation and billing credits to the 7(f) pool, in the absence of a corresponding assignment of the load reduction associated with conservation to that pool, BPA would create a situation in which the NR-1 rate would exceed the average cost of new resources. Under these circumstances it would not be cost effective for utilities to make the output of new resources available to the Administrator and purchase their load growth requirements from BPA as provided for in the Regional Act.

I believe there is sufficient justification supporting their suggestion. The basis for the determination of the NR-1 rate now alleviates this concern. First, the final rate proposal that I am recommending contains no billing credit costs since none could be adequately identified. Second, both the costs and the load reductions associated only with conservation on IOU systems are being assigned to the New Resource pool. The assignment of these load reductions to the New Resource pool reduces the extent to which this pool must rely on purchase power. In this rate year and in most cases the cost of conservation programs funded by BPA will be less than the cost of new resources added to the New Resource pool. Finally, the use of Federal resources, which would otherwise be secondary, to meet a portion of the New Resource pool load and to displace high incremental cost resources, will further reduce the NR-1 rate to a level for firm power shaped to load that is expected to be attractive to utilities that would be eligible to purchase under this rate.

Appendix

List of Abbreviations

Party	Abbreviation	Exhibit
Association of Public Agency Customer	APAC	PA
Association of Washington Gas Utilities	AWGU	GU
Bonneville Power Administration	BPA	BPA
California Energy Commission	CEC	CU
California Public Utilities Commission	CPUC	CU
City of Los Angeles, et al	LA	CU
CP National Corp.	CPN	
Direct Service Industries	DSI	DS
Hanna Nickel Smelting Co.	Hanna	DH
Idaho Power Company	IPC	IO
Idaho Public Utility Commission	IPUC	SC
Intercompany Pool	ICP	IP
Irate Ratepayers	IR	
Joint Customers Proposal	JCP	JCP
Liquid Air Coporation	LAC	
Los Angeles Dept. of Water and Power	LADWP	CU
Montana Power Company	MPC	IO
Northwest Irrigating Utilities	NW Irrigating	PB
Oregon Public Utility Commission	OPUC	SC
Pacific Gas and Electric	PG&E	CU
Pacific Northwest Generating Co.	PNGC	PB
Pacific Power and Light Company	PP&L	IO
Peoples Organizaton for Washington Energy Resources	POWER	WO
Portland General Electric	PGE	IO
Public Generating Pool	PGP	PB
Public Power Council	PPC	PB
Puget Sound Power and Light Company	Puget	IO
Seattle City Light	SCL	PB
Southern California Edison Company	SCE	SE
Utah Power and Light Company	UP&L	IO
Washington Public Utility Districts	WPUD	PB
Washington Utilities and Transportation Commission	WUTC	SC
Washington Water Power Co.	WWP	IO