ADMINISTRATOR'S RECORD OF DECISION

1981 TRANSMISSION RATE PROPOSAL

AND

1981 WHOLESALE POWER RATE PROPOSAL

PREPARED BY

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

JUNE 1981

Foreward

The purpose of this record of decision is to explain the process by which the Administrator of the Bonneville Power Administration (BPA) developed 1981 wholesale power and transmission rates. The document follows the development of the rates, beginning with their legislative foundation and concluding with the rate schedules which will be used to compute customer's bills beginning July 1, 1981.

The document describes each of the studies underlying the new rates. It also describes how the issues, comments, and suggestions from the rate hearings influenced the final decision on rates. The background information contained here is intended for those who desire a detailed understanding of the Administrator's decision.

BPA began to prepare its rate filings more than 18 months before the rates were scheduled to take effect on July 1, 1981. BPA proceeded to develop the new rates based on repayment of the federal investment in the Columbia River generating system and on the agency's duties under Federal laws existing at the time. On December 5, 1980, the President signed into law the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), which greatly expanded BPA's responsibilities. The Regional Act directed that BPA prepare immediately to provide an adequate supply of electricity for the region. This new responsibility had a profound impact on rate development already in progress.

BPA had six months to make adjustments in the rate proposal necessary after passage of the Regional Act. Provisions in customers' current contracts required that the July 1, 1981 deadline be met or that the rate adjustments be delayed until July 1, 1982. However, current fiscal obligations and the requirements of the new Regional Act necessitated that the adjustment be made on schedule.

Given this time constraint, BPA began immediately to carry out the new public involvement process required by the Regional Act for ratemaking. Public hearing sessions were held throughout the Pacific Northwest to encourage public participation. Formal proceedings before a hearing officer gave numerous parties an opportunity to present evidence and cross-examine witnesses. Customers, public interest groups, government representatives, and others were among the formal parties to the proceeding.

The record that resulted from this process was voluminous -- more than 6,000 pages of testimony and briefs. So extensive was the examination of issues and so complex the questions raised by implementation of the Regional Act that the hearing had to be extended beyond the planned time frame. The proceeding was closed for wholesale power rates on May 4, 1981, and for transmission rates on May 27, 1981.

In reading the Record of Decision, it is important to keep in mind the new and unfamiliar factors brought into the 1981 rate deliberations by passage of the Regional Act. BPA had to consider the rate impacts of new power sales contracts, which were being negotiated with customers in separate proceedings but simultaneously with the rate hearing. The scope of the contracts and the costs of power that would be sold by BPA to its various types of customers under the new agreements had to be projected and taken into account in the setting of the new rates. The costs associated with launching new conservation and renewable energy programs also were reflected in the new rates.

BPA had to revise the data in its studies to reflect the new obligations brought about by the Regional Act and to take advantage of the most current information available. The tables for each study are accompanied by a short introduction explaining basic steps in the studies. These tables can be used to gain an understanding of how and why changes were made for the final rate proposal.

The lengthy hearing process and the short time period available to adapt the rate proposal to new obligations under the Regional Act necessitated some changes in the presentation of rate studies. A short introduction explains the basic steps in the studies, which contain data on which decisions were based. For a complete narrative description of methodology, however, the reader should refer to the studies used to develop the Administrator's initial wholesale power and transmission rate proposals.

In cases where methodology or approach to studies has been modified since the initial proposal, the reader should rely on the Administrator's Record of Decision to interpret the tables accompanying the final rates. The Record of Decision contains a description of the methodologies used for the final rates. The narrative focuses on those areas where there has been a change between the initial and final rate proposals.

In future rate filings, BPA intends to provide a full narrative in each of the final studies with accompanying tables in a format similar to that of the initial rate proposals.

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I. <u>Introduction</u>

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 transmission rate schedules (Exhibit A) and wholesale power rate schedules (Exhibit B). The attached schedules will hereby be submitted to the Department of Energy's Assistant Secretary for Conservation and Renewable Energy for interim approval. These rate schedules will then be submitted to the Federal Energy Regulatory Commission (FERC) for final confirmation and approval. The rates are to become effective on July 1, 1981.

The wholesale power rate and transmission rate schedules are based on seven studies conducted by BPA and the comments and suggestions received throughout the ratemaking process. The studies include: (1) a Repayment Study to determine revenue requirements; (2) a Long-Run Incremental Cost (LRIC) Analysis to evaluate the additional costs faced by BPA in meeting load growth; (3) a Cost-of-Service Analysis (COSA) to identify the embedded costs associated with providing BPA's various services; (4) a Time-Differentiated Pricing Analysis (TDPA) to determine cost variation as a function of time of service; (5) a Transmission Rate Design Study (TRDS) that integrates the results of the preceding studies to develop transmission rate schedules; (6) a Wholesale Power Rate Design Study (previously called Summary Rate Design Study) that outlines the ratemaking process, including adjustments based on the results of the other studies used in developing the specific wholesale power rate schedules; and (7) an Environmental Assessment of the wholesale power rate filing. These studies were originally published on February 17, 1981, to support the initial rate proposals. They were revised in the process of developing the final rate schedules and summaries of these revisions are documented herein. The Rate Development Process Flow Diagram schematically presents the function of each study and the input of parties and participants in the rate development process.

The transmission rate development process began with BPA's "Notice of Intent to Revise Transmission Rates", published in the <u>Federal Register</u> on May 25, 1979 (44 FR 30405). A "Notice of Intent to Develop Revised Wholesale Power Rates" was published in the <u>Federal Register</u> on June 12, 1980 (45 FR 34885). These notices were published prior to the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) which became law on December 5, 1980. In the Notice of Intent, BPA estimated, based on preliminary examination of revenue requirements prior passage of the Regional Act, the need for a revenue increase of approximately 50 percent to meet its repayment obligation for Federal Columbia River Power System (FCRPS) resources. Rate increases to individual customers which were both above and below this 50 percent level were not forecasted in June 1980. Further, BPA specifically requested public comment regarding the development of its initial rate proposals. The comment period on the development of the initial proposals was to have closed on October 31, 1980, but was later extended through December 1, 1980 (45 FR 70541, October 24, 1980) to allow additional time for public participation.

The 50 percent estimate was based on an initial repayment study for the FCRPS. This repayment study tested whether revenues under existing rate schedules, assuming average water conditions, would meet BPA's obligations to recover the cost of producing, purchasing, and transmitting electric power and to repay, with interest, the Federal investment in the FCRPS as required by statute. At the time this Repayment Study was undertaken in September 1980, the Regional Act was still pending before Congress. At the time it was intended that the new wholesale power rates and transmission rates based on this study would be adequate to produce the necessary increase in total revenues. However, passage of the Regional Act on December 5, 1980, provided BPA with additional statutory obligations, as well as directives concerning the determination of the rate to be applied to carry out its new and existing obligations.

In addition to a new rate process that was presented by the Regional Act, its passage late in the 1981 rate development schedule created additional complexities in meeting the July 1, 1981, deadline for filing new wholesale power rates. The costs associated with resource purchases which are either required or allowed by the Regional Act were unknown; specifically, costs of new resources to serve investor-owned utilities (IOU) deficits and load growth, and average system costs for residential exchange resources. The loads associated with the above resources were also unknown. Both resource costs and loads will remain indeterminant until contracts are signed and the amounts of IOU deficit, load growth, and residential exchange placed on BPA are determined. An additional complication was incorporation of costs associated with the Regional Act into the repayment study process. This was not accomplished until the final rates were developed. A final complication that has impacted the rate development process is the cash flow impact of the Regional Act on BPA's financial operations. Because BPA must purchase additional resources to serve new loads, BPA's cash needs will increase and the agency must assure itself that cash collected through its monthly power bills matches the cash needs of the new obligations.

On February 17, 1981, BPA published its initial proposals to revise transmission and wholesale power rates in the Federal Register (46 FR 12659). Based on these proposals, which incorporated the most current cost and load data available at that time, BPA determined the need for a revenue increase of approximately 53 percent from preference customers served by Federal base system resources. In addition, the proposed rates would have recovered revenues from other existing power sales and wheeling customers, and revenues from new sources associated with BPA's expanded service obligations under the Regional Act. These expanded obligations include service to the residential and small farm loads of the region's investor-owned utilities (IOU), service of the deficits of the IOU's, and service of preference customer and IOU load growth.

In accordance with the provisions of the Regional Act, BPA commenced its formal hearing process on March 2, 1981, at Portland, Oregon. During the week of March 2-6, 1981, the BPA staff presented a technical description of the transmission and wholesale power rate proposals. Clarifying questions were permitted by all parties to the proceedings. Six additional presentation/clarification hearings were held at Salem, Oregon; Missoula, Montana; Boise, Idaho; Richland and Seattle, Washington; and San Francisco, California. The locations were selected to make possible public participation throughout BPA's marketing area. Parties were given an opportunity at each hearing to express comments and suggestions regarding the proposals.

The hearing process continued on March 30, 1981, with formal cross-examination of the BPA staff by the parties to the proceedings as well as cross-examination of the parties by BPA and by each other. This was followed by general rebuttal period and the presentation of a revised Repayment Study, which was subject to cross-examination by all parties. The hearings closed for wholesale rates on May 4, 1981, and for transmission rates on May 27, 1981.

Substantial public interest was evident during BPA's rate process. Thirty-seven parties of record actively participated in the formal rate hearings and the general public was invited to participate in the hearings. Additionally, BPA received over 300 letters, telephone calls, and technical reports regarding its rate policies and proposed revisions.

This significant public comment, both supportive and critical, coupled with BPA's cost and rate studies form the basis for BPA's final rate proposals. The Staff Evaluation of Official Record identifies the issues raised by the general public and the parties to the hearing process, and discusses the staff's evaluation of the positions of these groups. Written comments on the proposed wholesale rates were accepted through the close of the hearings and were evaluated by staff in the Staff Evaluation. Comments on the proposed transmission rates received on or before May 15, 1981, were also evaluated in the Staff Evaluation. Comments on the transmission rate proposal received from May 16, 1981, through May 27, 1981, were addressed in an addendum to the Staff Evaluation. The parties to the case had an opportunity to comment on the Staff Evaluation of Official Record.

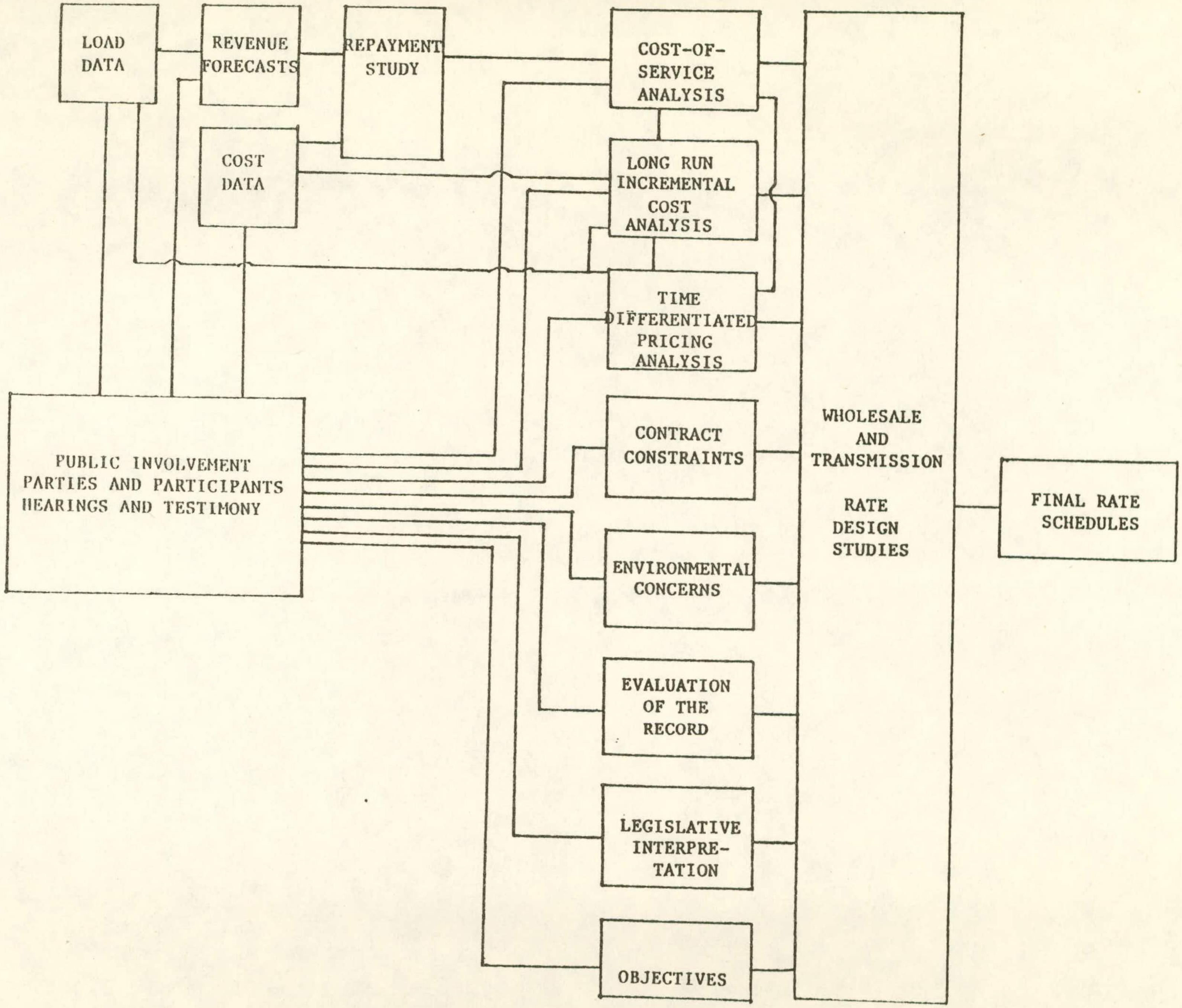
Following the close of the hearing, BPA completed a final repayment study that indicates the need for a 78.5 percent increase in revenues. This increase includes all costs associated with BPA's existing obligations plus all costs directly associated with the Regional Act, with the exception of costs for exchange resources purchased from investor-owned utilities. Under existing rates BPA would collect approximately \$630 million in FY 1982. Under the proposed rates, revenues will total \$1.1 billion plus an expected \$350 million to \$500 million collected for purchase of exchange resources from investor-owned utilities. The amount of the exchange purchase has not been determined because the methodology for that determination requires, under law, a separate review process and separate approval by FERC. The impact of the rate increase on Bonneville's preference customers averages 59.4 percent. The range of increases for these customers is 45.4 percent to 64.2 percent after adjusting for the low density discount. The average increase for municipalities, public utility districts, cooperatives, and Federal agencies is 62.4 percent, 61.0 percent, 52.1 percent, and 60.9 percent respectively.

The impact of the rate increase on the direct service industrial customers (DSI's) is difficult to quantify because the rate level after October 1, 1981, depends on the costs of the exchange resources as defined in Section 5(c) of the Regional Act. Because this cost is not known at this time, an estimate of values for the average per unit cost of the exchange has been made. Assuming a range of average system cost values from 18 to 25 mills per kilowatthour, the percentage increase to the DSI's would be from 166 percent to 240 percent.

The impacts of this proposal on the investor-owned utilities (IOU's) are two-fold. First, any IOU that participates in the residential exchange as provided for in Section 5(c) of the Act, will be able to purchase an amount of power equivalent to 60 percent of the utility's residential and small farm load during the rate period beginning July 1, 1981 at the same rate charged to Bonneville's preference customers. This average rate will be about 11.3 mills per kilowatthour. 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-1 rate. Assuming a 70 percent load factor, the average rate to these customers will be 32.4 mills per kilowatthour.

Bonneville markets a considerable amount of nonfirm energy to Pacific Southwest utilities under its nonfirm energy rate schedule. There should be a very small impact on these customers from the new nonfirm energy rate. Although this is a variable rate, the per kilowatthour charge under this rate is expected to average 9.6 mills. This represents only 1.6 mills per kilowatthour increase over what would have been expected under the current rate. This is the first time that a nonfirm energy rate will be in place that is expected to recover, on average, less revenue than would have been received if the rate had been set equivalent to the average firm power rate.

RATE DEVELOPMENT PROCESS



II. Legal Requirements

A. General Rate Guidelines

Section 6 of the Bonneville Project Act (50 Stat. 735 as amended by 59 Stat. 546) 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 by the Federal Power Commission, such rate schedules may be modified from time to time by the A20inistrator, 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 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. 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."

The foregoing requirements are similarly restated in the Regional Act. Section 7 of the Act 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 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) 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 upon 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 such uncompleted projects in its annual reports to the President and Congress. The exclusion of projects not yet in service is based upon 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 upon 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 upon these requirements, we 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. Based on that finding, we developed wholesale power and transmission rates in an initial form and finally in the form appended hereto.

I find that such 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 Exhibits A and B 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. The rate schedules continue the postage stamp rate policy, a policy that has served to carry out the statutory command to encourage the widest possible diversified use of electric power, and as expressed above, at the lowest possible rates to consumers on a systemwide basis.

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; a cost-of-service analysis to identify the costs associated with providing BPA's various services; a time-differentiated pricing analysis to determine cost variations as a function of time of service; and a long run incremental cost analysis of the generation and transmission system to determine the cost of providing future increments of generation and transmission service.

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 FCRPS COSA, that portion of the transmission system not used to serve wheeling customers was segregated from revenue requirements allocated to wheeling services by segmenting the transmission system into seven segments. I find that this approach has permitted the recovery of the cost of the transmission system of the FCRPS to be equitably allocated between Federal and non-Federal power utilizing that system.

D. <u>Equitable Sharing of Benefits by Regions</u>

In addition to the general rate guidelines and those relating to transmission, the Administrator of BPA is 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, <u>although</u> discussing permissible <u>exchanges</u> 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 indicate clearly that in enacting the Regional Preference Act it was contemplated that there should be a continuing and mutual sharing of benefits between the Pacific Northwest and the Pacific Southwest in all power sales, not just exchanges of energy or capacity under Section 5 of the Preference Act. Pursuant to that Congressional expression, I have adopted the NF-1 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. Regional Power Act Rate Pools

In addition to providing general revenue requirement guidelines, the Regional Act also establishes three rate pools. Section 7(b)(1) of the Regional Act establishes 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, upon 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 arguments of the various parties, including those raised in the briefs of Puget Sound Power and Light Company, (pp. 4-30), Portland General Electric Company (Supplemental response pp. 2-7) and BPA Counsel (pp. 36-48) 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. Based primarily upon express Congressional intent that the 7(f) rate be a "new resource" rate and a corresponding absence of any indication that the DSI's are to pay any additional costs beyond the costs of the 5(c) exchange (which causes an increase in their rates of between 166 and 240 percent), I determined that the DSI's are to be served from Federal base system resources left over after serving those customers entitled to be served under Section 7(b) the remainder of their load will be served with resource firm Section 5(c) exchange.

I believe that this view is consistent with a statement made by one of the primary sponsors of S. 885 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 (long. 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 net costs of residential exchange under this Regional Act. 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.

As explained in this Record of Decision, I conclude that the 7(f) rate is to be primarily a new resource rate which will benefit from the existence of the Federal base system through displacement of certain purchases which would otherwise be necessary to serve such loads.

As discussed herein, I find that the purchases necessary to increase the size of the Federal base system to the level it would have been absent the Regional Act are appropriate and operationally sound. Furthermore, I find that the public body, cooperative, and Federal agency customers within the Pacific Northwest and residential exchange loads have been allocated their fair share of Federal base system costs needed to supply those loads.

F. Confirmation and Approval

While the Bonneville Project Act and the Federal Columbia River Transmission System Act refer to the confirmation and approval by the Federal Power Commission, that entity was dissolved by the Department of Energy Organization Act (Pub. L. 95-91, August 4, 1977). The functions of the Federal Power Commission relating to Federal Power Marketing Administration rate approval were transferred to the Secretary of Energy by Section 301(d) of that Act (91 Stat. 578).

Prior to enactment of the Regional Act, rates deveoped by the Secretary of Energy, acting by and through the Administrator of the Bonneville Power Administration, were subject to confirmation and approval on an interim basis by the Assistant Secretary for Resource Applications of the Department of Energy pursuant to Secretary of Energy Delegation Order No. 0204-33, (December 28, 1978). That same Delegation Order delegated to the Federal Energy Regulatory Commission the authority to confirm and approve rates on a final basis and to allocate costs for the various purposes of the projects required to be allocated by Section 7 of the Bonneville Project Act and Section 2 of the River and Harbor Act of 1945 (59 Stat. 10, 21, 22).

Section 7(a)(2) of the Regional Act 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 7(i)(6) of the Regional Act provides, with regard to interim approval:

"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 1 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."

In accordance with the above-noted provisions, FERC, in a letter dated April 10, 1981, from Georgiana Sheldon, Acting Chairman, FERC, to James B. Edwards, Secretary of the United States Department of Energy, noted that the Commission has determined the necessity to establish procedures for interim approval of BPA's rates. Consequently the Commission notes, pursuant to Section 7(i)(6), that the Secretary of Energy is authorized to approve interim rates during the 1-year period commencing with the enactment of the Regional Act. The interim approval authority of the Secretary of Energy has been delegated to the Assistant Secretary for Conservation and Renewable Energy pursuant to Secretary of Energy Delegation Order No. 0204-33 as amended by Order of June 19, 1981.

III. 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.

One procedure available under NEPA is the determination that a given action clearly is not a major Federal action which would significantly affect the quality of the environment and action, therefore, does not require preparation of either an Environmental Assessment or an Environmental Impact Statement. This procedure was applied to BPA's transmission rate proposal. The Environmental Determination (sometimes called a brief memorandum to the files) that documents this decision is on file at BPA Headquarters. Copies are available from the BPA Environmental Manager, P.O. Box 3621, Portland, Oregon 97208.

Another procedure is preparation of an Environmental Assessment (EA). An EA 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 EA 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 EA was prepared on BPA's wholesale power rate proposal and circulated to the public for review and comment. Notice of availability of the EA was published in the Federal Register (46 FR 12659) on February 17, 1981, and comments on the EA were accepted through the close of BPA's formal rate hearings on wholesale power rates on May 4, 1981. Subsequent to the close of these hearings, a Final EA was prepared based on the Draft EA and comments received on the Draft EA. Based on information in the Final EA the Department of Energy has determined that the wholesale power rate proposal is not a major action with significant environmental effects. The Department signed a Finding of No Significant Impact (FONSI) on BPA's wholesale rate proposal. Copies of the Final EA and FONSI are available from the BPA Environmental Manager.

B. Transmission Rate Filing

1. Decision

I have decided to submit to the Department of Energy a proposal to adjust BPA's transmission rates in order to recover a 43 percent increase in the amount of revenue that would otherwise be recovered under current transmission rates. This increase would allow BPA to collect its statutorily mandated revenue requirement. In order to achieve this increase, I am submitting two sets of transmission rates from which BPA's customers may choose (Set A and Set B), as shown in the attached transmission rate schedules. The Set A rates are an updated version of BPA's current transmission rates. Set B rates consist of a uniform, postage stamp rate for use of the transmission network and a schedule for Pacific Northwest/Pacific Southwest intertie use.

I have chosen to provide a 1-year interim contract period from July 1, 1981, to June 30, 1982, during which transmission customers may choose the set of rates that will apply to them. As a result of offering this rate option, BPA anticipates a small revenue shortfall as a result of customers choosing the option that will minimize their cost for transmission services. In order to avoid the anticipated shortfall, I have chosen to adjust the Set A and Set B rates to recover the anticipated shortfall from each set, proportional to the projected use of transmission services by customers selecting each set.

2. Alternatives Considered and Environmental Impacts

a. Environmental Analysis

A two-part Environmental Determination of the effects of the proposed transmission revenue increase was conducted by the BPA staff as part of the transmission rate proposal. The first part found that the proposed 43 percent increase would be less than the general rate of inflation since the most recent (July 1, 1977) BPA transmission rate increase. The general increase in the level of prices as measured by the Consumer Price Index for the July 1, 1977, to July 1, 1981, period is projected to be between 50 and 55 percent. (See memo to John Palensky from Robert Diffely, 2/5/81.)

U.S. Department of Energy Final Guidelines for compliance with the National Environmental Policy Act (NEPA) categorically exclude rate increases "which do not exceed the rate of inflation in the period since the last rate increase" from EA or EIS requirements (45 F.R. 20700). Therefore, the proposed transmission rate increase may be categorically excluded from further environmental analysis.

The second part of the Environmental Determination was conducted to assure that BPA fully complied with the intent of NEPA and adequately considered environmental concerns. The primary focus of this analysis was to determine if an increase in BPA's transmission rates would stimulate the construction of parallel transmission facilities by other utilities. It was presumed that such construction would have significant potential for impacting the physical environment. A worst-case analysis was performed that assumed a 60 percent rate increase applied to the Seattle City Light - Boundary Project contract. This particular contract was examined because wheeling costs constitute a larger portion of total costs for Seattle City Light than for any other utility in the region. In addition, Seattle City Light pays a higher wheeling charge per megawatt than any other BPA transmission customer. (See memo to Robert Diffely from Spencer Wedlund, 7/13/79.) The results of this analysis indicated that it currently would not be economically feasible for Seattle City Light to construct parallel facilities from the Boundary project to their load area. Therefore, it was concluded that a transmission rate increase as high as 60 percent would have no significant impact on the physical environmental.

The level of transmission rates generally does not have a substantial impact on the costs of wheeling utilities' retail customers and consequently does not significantly affect their consumption of electricity. In this worst-case example, BPA found that a 60 percent increase in wheeling rates would affect retail consumption by less than 0.5 percent (See memo to John Palensky from Robert Diffely, 9/24/79.) Based on the results of this study, I believe BPA's transmission rate increase does not constitute a major Federal action significantly affecting environmental quality.

I concur with the BPA staff recommendation to individually exclude this rate action from further environmental analysis and my signature to this document signifies that concurrence.

b. Revenue Level Alternatives

Three revenue level alternatives were considered prior to proposing the 43 percent transmission rate increase. Based on the worst case analysis just described, it was concluded that no adverse environmental impacts would be associated with any of the alternatives considered.

(1) I considered the alternative of either proposing no transmission rate increase or postponing the implementation of an increase at this time. There would be no adverse environmental impacts associated with this option. However, this option would result in an approximate $1.7 million monthly loss of revenue to BPA. Recommending this option would require that wholesale power rates be increased further. Additionally, this option would place BPA in violation of its statutory requirements to equitably recover the allocated costs of the FCRTS from Federal and non-Federal customers.

(2) As a second alternative, I considered recommending the required 43 percent revenue increase without attempting to account for the possible small revenue shortfall that might result from uncertainty about the number of customers choosing Set A or Set B rates. This revenue shortfall is projected to be approximately $1.8 million for fiscal year 1982 based on preliminary indications received from customers expressing a preference with regard to the IR-1 rate. This alternative was rejected because it would have violated BPA's previously described statutory requirements regarding cost recovery.

(3) The third alternative I considered was to recommend the 43 percent wheeling revenue increase and adjust the wheeling rates as necessary in order to eliminate the previously discussed revenue shortfall. This alternative was selected because it is consistent with BPA's statutory

requirements and would not result in significant adverse environmental impact.

3. Avoidance of Impact

The average increase in transmission rates that I am proposing would be less than the increase in the price of consumer goods, as measured by the Consumer Price Index, since the last BPA transmission rate increase and, hence, in itself cannot be considered a severe increase. Therefore, I do not consider the potential economic effect of the proposed transmission rates to constitute a significant impact on BPA's customers or the consumers they serve.

C. Wholesale Rate Filing

1. Decision

I have decided to submit to the Department of Energy a proposal to adjust BPA's wholesale power rates in order to achieve a total revenue increase (including the proposed increase in transmission revenues) of 78.5 percent. The decisions I made regarding the proposed wholesale power rates are incorporated into the wholesale power rate schedules attached to the order as Exhibit B. I have made these recommendations based on a comprehensive review of BPA's Final EA as well as all other materials appurtenant to the rate process. The proposed rates would permit BPA to collect sufficient revenue to meet its staturtorily mandated repayment requirement. The proposed rate adjustment is scheduled to become effective on July 1, 1981.

2. Alternatives Considered and Environmental Impacts

A number of alternative revenue levels and rate designs were evaluated in the EA. These alternatives were selected in a manner intended to insure consideration of the range of all reasonable alternatives.

a. Revenue Level Alternatives

BPA examined several revenue alternatives in order to fully assess the potential range of environmental implications of wholesale power rate increase. Two revenue alternatives that would precipitate lower revenue increases than that proposed by BPA are (1) a "no action" alternative under which BPA would maintain its existing rates and (2) a 30 percent increase alternative that was based on exclusion of any payments for nuclear plants under construction until their dates of commercial operation. The proposed 78.5 percent increase is based on BPA's repayment requirement as indicated in the final Repayment Study. An alternative in which rates would be based on long run incremental costs also was considered. This alternative would have resulted in a revenue increase of approximately 720 percent. These alternatives are outlined more fully in Section II(A) of the final EA.

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 July 1, 1981, rate proposal is not expected to have serious economic consequences for the Region's electricity consumers (EA Chapter III(B)(5)).

It is my conclusion after reviewing all pertinent information that the proposed 78.5 percent revenue alternative would not significantly impact the physical environment. Furthermore, I believe that the socioeconomic effects of the 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 the proposed rate increase may include reduced growth in the demand for electricity, 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. <u>Rate Design Alternatives</u>

BPA considered several potentially feasible rate design alternatives during the development of its proposed rates. These alternatives include rates set according to the "inverse elasticity" rule, tiered rates, long run incremental cost (LRIC) based rates, a fixed rate for nonfirm energy, share-the-savings rates, and time-differentiated rates. Several approaches to industrial value of reserve credits also were considered in designing the proposed rates. In addition, the impact of increased electric rates on irrigated agriculture was considered. The factors of equity, economic efficiency, administrative feasibility, rate and revenue stability, cost causation, conservation, and environmental protection were considered in evaluating the alternatives.

(1) Application of the Inverse Elasticity Rule

Statutory limitations preclude BPA from recovering the amount of revenue that would be collected under rates based on marginal costs. Given these limitations, BPA considered the feasibility of a PF-1 rate schedule based on the inverse elasticity rule as an alternative means of encouraging efficient use of electricity. This type of rate structure would entail setting higher rates for those electricity customers with relatively elastic (price sensitive) demand and lower rates for those customers with relatively inelastic (price insensitive) demand. According to economic theory, this would promote a more efficient utilization of available electric resources by inducing customers who can more easily switch to alternate fuels, or conserve, to do so. Also, those customers least able to alter their electricity consumption patterns would face somewhat lower rates.

One problem that BPA would encounter in applying the inverse elasticity rule to electricity rates is that BPA has no reliable estimates of elasticities for individual customers and/or customer classes. Available studies show relatively wide variations in estimated elasticities and these elasticities may also change over time (Wholesale Summary Rate Design Study (WPRDS), Appendix B, and Staff Evaluation, Chapter 8(IV)(B)(2)(e)). In the absence of more reliable data, a well defined application technique, and conclusive evidence indicative of significant environmental benefit, I have decided that the inverse elasticity rule is not a viable mechanism under which BPA can design its rates in a defensible, prudent manner.

(2) Tiered Rates

Under a tiered rate structure, the price of electricity would vary with the quantity consumed. To the extent tiered rates are based on discrete consumption intervals, they are commonly called declining block rates (unit price decreasing as consumption increases) or inverted block rates (unit price increasing as consumption increases). The inverted block pricing scheme has been advanced by some sources as having the potential to promote conservation. With unit power cost increasing as consumption increases, the consumer is purported to have an increased incentive to reduce consumption. There is widespread disagreement, however, as to what actual consumer response would be to such a rate structure, especially at the wholesale level.

An assessment of the potential for tiered rates to encourage conservation is contained in Appendix B of BPA's 1981 Wholesale Power Rate Design Study (WPRDS). In the absence of convincing data supporting a conservation effect for tiered rates (WPRDS, Appendix B and the Staff Evaluation, Chapter 8(IV)(B)(2)(d)), I have opted to continue with a melded hydro/thermal rate consisting of fixed capacity and energy charges that may vary with the time of day or season in which service is provided. This is more completely elucidated in the WPRDS. The present uncertainty as to whether a tiered wholesale rate structure can promote conservation or provide rate relief to low-income groups as discussed in relevant portions of the EA, WPRDS, and Staff Evaluation, causes me to feel that the potential environmental effects associated with the implementation of a tiered rate structure would be insignificant.

(3) Long Run Incremental Cost Based Rates

Long run incremental cost based rates (frequently called marginal cost rates or pricing) would entail pricing electricity at the cost of providing additional increments of service. Prevailing economic theory holds that under perfect competition and a given income distribution, incremental pricing will promote the optimal allocation of society's scarce resources. LRIC pricing applied to BPA's rate structure would result in a 720 percent increase in BPA's revenue level. This would far exceed BPA's revenue requirement (EA, Chapter II(A)(3)), would violate BPA's statutory mandate to provide electricity at the lowest possible cost consistent with sound business principles, and would have a large negative impact on the socioeconomic vitality of the Pacific Northwest (EA, Chapter III, and Staff Evaluation, Chapter 8(IV)(B)(2)(e)). Therefore, I do not consider LRIC-based rates as a viable alternative at this time from either a business or environmental perspective.

The results of BPA's LRIC, however, are reflected to a limited extent in BPA's proposed rates. These results were used as a basis for crediting excess revenues from nonfirm energy sales to capacity and energy costs. They also were used as a basis for classification of generation costs in BPA's COSA.

(4) Fixed Nonfirm Energy Rate

In developing the proposed NF-1 nonfirm energy rate, BPA considered implementing a fixed flat rate that would not vary by time or quantity of service provided. If a fixed rate were established, it would have to be relatively low to ensure that BPA would be able to market its nonfirm energy during periods of excess streamflow. Also, a fixed rate would not necessarily be cost based since the incremental cost of energy produced from existing hydro facilities is relatively low and consequently might require a shifting of the cost burden to customers making purchases under other rate schedules. As a result, to allow BPA flexibility to respond to market conditions and the ability to displace higher cost thermal generation on a cost priority basis, and to more closely adhere to cost based pricing principles, I have decided that the NF-1 rate should be based on costs of power provided by hydro facilities, power purchases, and all other resources that contribute to the production of nonfirm energy. Because the rate is cost based, customers receiving this service will be assured equitable treatment and will pay their proper share of power supply costs. Furthermore, I find support in the record for the conclusion that so long as the cost of nonfirm energy is lower than the alternative cost of oil fired generation, the oil fired generation will be displaced, with the resultant environmental benefits of reduced air pollution.

(5) Share-the-Savings Nonfirm Energy Rate

Another alternative considered for possible inclusion in the NF-1 rate schedule was continued use of the share-the-savings concept reflected in the existing H-6 rate schedule. In order to more fully meet cost-based rate objectives, however, I have decided not to include a share-the-savings concept in this rate schedule. I further believe that the amount of power sold under this rate schedule will not vary as a result of this revision. Therefore, there should be no environmental significance in shifting from a share-the-savings to a cost based nonfirm energy rate. The proposed NF-1 rate is outlined briefly in the preceding section and described more fully in the attached Exhibit B.

(6) Time-Differentiated Rates

Alternative approaches considered by BPA regarding time differentiation of rates included rate differentials reflecting average, marginal, and constrained marginal costs. The option of excluding time differentiation from the rate structure was also considered.

Time differentiation of rates could tend to enhance environmental quality by reducing the peak demand required to be met by Federal hydroelectric facilities and thus slightly smoothing BPA's demand curve. However, the extent of this effect would be minor relative to total river fluctuation and would not be expected to result in a significant environmental benefit (EA, Chapter III(B)(2)(d)). Apart from any tendency to reduce peak demand, time-differentiation of rates enhances achievement of BPA's objective of allocating the costs of providing service to those customers or customer classes demanding such service. Thus, a time-differentiated rate structure appears to be environmentally amenable and in keeping with cost based pricing principles.

Therefore, I have decided to include peak period energy and capacity charges in rate schedules PF-1, IP-1, and MP-1, based on the results of the TDPA, the LRIC, the EA and relevant portions of the Staff Evaluation.

(7) Industrial Reserve Credit

The proposed IP-1 industrial firm power rate schedule includes a adjustment to recognize the value of planning, operating, and stability reserves provided to BPA by this customer class as required by the Regional Act. The proposed IP-1 rate schedule differs significantly from the existing IF-2 rate schedule. Under the existing IF-2 rate, direct-service industrial (DSI) customers receive reserve availability credits only when BPA actually exercises restriction rights on DSI loads. Under the proposed IP-1 rate, the value of reserves credit is calculated and this amount is then netted out of DSI allocated costs, resulting in a lower unit rate. BPA and its customers benefit from the restriction provisions of the IP-1 rate and I feel that the rate schedule should be adjusted accordingly to provide appropriate recognition of this benefit. The development of the reserve credit is described in detail in BPA's 1981 Wholesale Power Rate Design Study, Appendix A.

BPA considered several alternative methods of calculating DSI reserve credit. One option would have been to eliminate any compensation to the DSI's for contractual restriction rights. I feel, however, that the ability to restrict load under various conditions is a tangible benefit to all BPA customers and the granting of a credit is consistent with cost based pricing objectives and equitable treatment of all customer classes.

Another approach would have been to base the amount of the credit on a different criterion than that used to develop the amount reflected in the proposed IP-1 rate; for example, valuing capacity and energy at LRIC. The granting of a credit equal to an LRIC valuation of the DSI reserves, however, given that the DSI's would be purchasing power from BPA under a constrained incremental cost-based rate structure, would tend to over compensate the DSI's for the restriction rights. Ultimately, a melded average cost/long run incremental cost methodology was developed to calculate IP-1 demand and energy charges with appropriate compensation for restriction rights. I believe this approach is appropriate and would not result in significant environmental impact. Although the granting of an adjustment to the DSI's would lower their cost of power, the demand of the DSI's for electricity is relatively insensitive to price. The amount of cost reduction associated with the value of reserves adjustment would not significantly increase their demand for electricity. The increase in cost to other customers would not be sufficient to significantly discourage their consumption of electricity.

(8) Irrigated Agriculture

Electricity prices comprise a significant portion of the production costs associated with the Pacific Northwest's irrigated agriculture. BPA has taken this fact into consideration during the development of the rate proposal. The design of cost-based rates requires that electricity consumers placing capacity and energy demands on a utility system pay their proportionate share of service costs. BPA considered special rates for irrigation customers, but a special rate was not considered consistent with cost causality. A special rate for irrigators would amount, in essence, to a subsidy from BPA's other customers and would violate the rate equity principle.

There are, however, three features of BPA's rate proposal that may benefit significantly many irrigation customers. First, BPA has summer/winter rate differentials for both capacity and energy. The summer component is in each case lower than the winter component. Irrigators use power primarily during the summer season and can therefore benefit from this differential. Second, BPA's capacity charge varies subject to the time of day that capacity is taken. The structure of the offpeak period (10 p.m. to 7 a.m., inclusive, Monday through Saturday, and all day Sunday) allows irrigators (and other customers as well) to consume capacity offpeak over

45 percent of the hours in the week. There is no charge for capacity during the offpeak period. Third, pursuant to the provision of the Regional Act, BPA has developed a low density discount based on either customer density per mile or the ratio of energy to investment. The discount ranges from 3 to 7 percent and most utilities serving irrigation customers qualify for the discount. Thus, I feel that irrigators can take advantage of one or more of the above aspects of BPA's rate design and experience at least a partial mitigation of the impacts of higher utility costs.

3. Avoidance of Impact - Summary

All practicable means to avoid or minimize environmental harm have been incorporated into BPA's proposed rate schedules. The selection of the proposed 78.5 percent revenue alternative would produce no significant impacts to the physical environment. The seasonal and diurnal rate differentials in the proposed rates should provide price signals to electricity users that would encourage more efficient use of electrical power. This could thereby, potentially provide minor mitigation of environmental impacts associated with power production and also provide certain customer groups the opportunity to tailor their power consumption patterns to take advantage of the lower cost supply periods. The emphasis on proportionally greater increases in energy costs relative to capacity costs as reflected in the proposed rates could slow the rate at which new thermal power facilities must be added to the regional power system to meet increasing energy requirements, thereby limiting adverse impacts from the construction and operation of such facilities.

In addition to incorporating features in its proposed rates that minimize the potential for adverse impacts of the rates, BPA is also engaged in program areas such as energy conservation, renewable resource assessments and promotion, billing credits, and the BPA/IOU residential/small farm exchange that will ultimately aid in mitigating the unavoidable socioeconomic impacts associated with increases in the cost of electricity. I have submitted BPA's proposed wholesale rate schedules, cognizant of the environmental issues and ramifications as outlined in the EA, the Staff Evaluation, and the remaining appurtenant studies and hearing record.

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.

IV. Repayment Study

A. Introduction

As indicated 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 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 the power marketing operations of the BPA which purchases, transmits, and markets power, and the generating facilities of the Corps of Engineers (Corps) and Water and Power Resources Service (Service), formerly the Bureau of Reclamation (Bureau). Each entity is separately managed and financed, but the facilities are operated as an integrated power system and 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 revenue requirements that will repay all FCRPS costs.

BPA has a threefold objective in establishing the level of its power rates. On the one hand rate levels must be set sufficiently high so as to produce revenues adequate to recover power costs (Section 7 of Bonneville Project 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 (Section 5 of the Flood Control Act of 1944 and Section 9 of the Transmission System Act). At the same time rates must be set in accordance with sound business principles (Section 5 of the Flood Control Act of 1944, Section 9 of the Federal Columbia River Transmission System 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 FERC, is charged with allocating the costs of the Bonneville Project. Project authorizing legislation also makes FERC responsible 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 confer responsibility for developing cost allocations for these projects with the Secretary of the Army. The Secretary of the Interior is responsible for approving cost allocations for projects constructed by the Service. BPA usually participates in the development of the cost allocations for all projects.

The cost allocation methods used 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 System 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 development of 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 was also presented to Congress in conjunction with consideration of the authorization of the Grand Coulee Third Powerplant. 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.

"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 for Water and Power Resources 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 Land and Water Resources 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 Federal Columbia River Transmission System Act contains the further 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 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 Number RA 6120.2 on September 20, 1979.

C. Regional Act Costs

The Regional Act expands BPA's responsibilities in the region and requires 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 following additional costs have been included as a result of the Regional Act: (1) regional council, (2) fish and wildlife, (3) local government asssistance, (4) load requirements and forecasting, (5) public involvement, (6) system planning, contracts, and rates, (7) energy conservation (8) short-term power purchases to meet investor-owned utility deficits, (9) nonmajor renewables, and (10) investor-owned utility new resources (Table 20, COSA). The investor-owned utility exchange resource costs associated with Section 5(c) of the Regional Act have not been included in the Repayment Study; however, the costs have been included as an "X" in the COSA (Table 20). Upon completion of an average system cost methodology and approval of that methodology by FERC, those costs associated with the exchange will be recovered from the direct-service industrial customers.

D. 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.

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")

(c) the investment in each replacement of a power-generating facility 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.)

7. If 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:

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

(b) Amortization of power investment financed with appropriated funds,

(c) Interest on power investment financed with appropriated funds,

(d) 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.

E. Power System Repayment Study

The Power System Repayment Study projects estimated revenues and costs over the remainder of the repayment period for the entire power system to determine whether there will be enough revenue to recover all costs. 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, and the service life for each replacement. Each year the amount of new power investment made that year is added to the allowable unamortized investment. That same amount is also subtracted from the allowable unamortized investment at the end of its repayment period. Thus the resulting total for each year represents the maximum amount of power investment that can remain unamortized in compliance with the established repayment periods.

Consequently, the Repayment Study determines whether the repayment criteria are met by comparing the estimated future unamortized power investment with the allowable unamortized investment on a per project basis. 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.

F. Need for Revenue Increase

In compliance with statutory requirements and Department of Energy policy, the BPA staff prepared a Current Repayment Study to test the adequacy of the revenues from the existing rates. That study demonstrated that the revenues from the existing rates are insufficient to fully recover all costs as required. (See FCRPS, Bonneville Power Administration, Repayment Study Report for July 1, 1981, Final Proposals (Repayment Study Report), Exhibit 2, Current Repayment Study)

Since the last time power and wheeling rates were adjusted, there have been significant cost increases including the addition of new programs required by the Regional Act. These cost increases have not been matched by corresponding increases in revenue that have been limited to increases in the volume of sales. The cost increases include substantial increases in the cost of nuclear power plants from which BPA has acquired power generation capability; increases in other purchase power costs; and increases in costs to operate, maintain, and construct new Federal generation and transmission facilities. Interest costs also have increased considerably. Corps and Service projects now have an incremental interest rate of 9 percent, BPA is facing interest rates of 12 percent for funds it borrows from the Treasury, and the interest rate for financing the nuclear projects from which BPA has acquired the capability is expected to be approximately 11 percent.

The new programs required by the Regional Act add substantial costs and include the Regional Planning Council and programs for fish and wildlife, local government assistance, load requirements and forecasting, public involvement, system planning, contracts and rates, energy conservation, additional short-term power purchases, nonmajor renewables and new major resources (Table 20, COSA). Finally, revenues from the 1979 rate levels have been less than forecasted.

The final repayment study does not include any costs for the investor-owned utility exchange resources. BPA must acquire the power at the utility's average system cost. The average system cost will be determined independently from the rate filing using a methodology currently being developed. The dollar amount of exchange is represented by an "X" (Table 20, COSA).

G. Results

The final Repayment Study indicates the need for a 78.5 percent increase in revenues (Exhibit 3, Repayment Study Report). This increase includes all costs associated with BPA's existing obligations plus all costs directly associated with the Regional Act, with the exception of costs for exchange resources purchased from investor-owned utilities. Under existing rates BPA would collect approximately $630 million in FY 82 (Exhibit 2, Repayment Study Report). Under proposed rates revenues will total $1.1 billion (Exhibit 3, Repayment Study Report) plus between $350 million and $500 million collected for exchange resources from investor-owned utilities. The amount of the exchange purchase has not been determined because the methodology for that determination requires a separate review process and separate approval by FERC.

H. Revenue Requirement Issues

The revenue forecast and the subsequent Repayment Study, that utilized that forecast to determine BPA's revenue requirement for the initial wholesale power and transmission rate filings, were completed prior to passage of the Regional Act. Subsequent to passage of the Regional Act, modifications to the rate proposal were made to reflect provisions of the Regional Act to the extent possible. These modifications, however, were not similarly made to the initial revenue forecast nor incorporated in the Repayment Study to assure that all portions of the initial rate proposal were consistent.

The 1981 rate process mandated by the Regional Act was new to all parties. Consequently, a number of questions were raised by the parties regarding how BPA determines its expected revenues and costs. Suggestions were made as to how those processes could be improved. In most cases, those suggestions have been incorporated and the result, I believe, is a substantially improved product. In other cases, BPA is constrained by current Department of Energy directives from implementing the suggestions. Finally, there were some suggestions that arose as a result of differing interpretations of the newly passed Regional Act. In those cases, I have made a careful review of the positions of all parties and of the legislative history before reaching my conclusions, which I believe follow legistative directives and provide equity to electric customers in the region.

1. Accuracy of Revenue Forecast

Comments received regarding the initial revenue forecast included concerns that the projected loads needed to be updated to reflect the most current information, that revenue from the sale of power purchased to meet firm loads was not included in the forecast, and that there was a discrepancy in the purchased power expense included in the initial Repayment Study and the initial COSA. These concerns were addressed in the preparation of the final revenue forecast and the COSA (COSA). In the final Repayment Study, BPA used load data that formed the foundation for the 1980 "Long-Range Projection of Power Loads and Resources for Resource Planning".

As a result of long term load carrying responsibilities to the preference customers established by the Regional Act, additional adjustments were made to preference customer and DSI loads including a reduction of 492 average firm megawatts to primarily reflect historical discrepancies between projected and actual loads, and a 46 megawatt reduction to public agency loads for conservation resulting from BPA programs reflecting additional information received. The revenue forecast for the final Repayment Study included revenues from the sale of purchased power to the extent that purchased power is needed to meet existing public and Federal agency loads projected for the test year. While earlier versions of the Repayment Study did not include revenues from the sales of power purchased to meet firm load deficits for investor-owned utilities, rates were applied to those loads in the final revenue forecast to show that the rates recover revenues sufficient to meet repayment criteria.

BPA has reestimated the cost of power purchases to meet public and private utility deficits under critical water conditions after displacing to the extent possible those purchases with additional Federal energy generated under average water conditions. Under critical water conditions BPA is projecting the purchase of 496 average megawatts at a total cost of $ 159.9 million, plus the purchase of 208 average MW of power from PGE's Boardman plant for $88.1 million. The power purchase forecast under average water conditions is 266 average megawatts at a total cost of $104.7 million, plus the cost of purchasing power from PGE's Boardman plant of $173.8 million. The cost of purchasing power to serve the public and private utility deficits was split proportionally between the 7(b) and 7(f) rate pools, while the cost of purchasing output from Boardman was associated only with the 7(f) rate pool. The cost estimates from all identified power purchases were incorporated in the Repayment Study.

2. <u>Secondary Energy Analysis</u>

Nonfirm energy (used interchangeably with secondary in the record), for the purpose of this analysis, is the extra energy produced from average streamflows versus critical period streamflows. The analysis of nonfirm is, first, to determine the availability and amount of this "above critical" energy; second, to establish the amount used in meeting BPA's firm loads and finally the remaining amount available for marketing as nonfirm. In this proposal, BPA has used this production of energy beyond critical water capability, to the maximum extent possible, to displace expensive thermal power purchases which would otherwise be necessary to serve BPA's firm power deficit and to displace the operation of high incremental cost resources. In actual circumstances nonfirm or extra energy may occur as a result of firm load underruns or greater production capability of other resources.

The basis for the forecast of nonfirm revenues is the secondary energy analysis (SEA). The SEA projects sales by months for 40 historical water conditions to determine averages. For the initial proposal, this analysis projected regional sales of nonfirm energy and applied percentages to approximate Federal sales to the regional markets and thus, Federal nonfirm energy sales revenues. By using the regional analysis to forecast

Federal secondary there was the possibility of attributing sales of more or less secondary than could be generated by the Federal system. This would result in a forecast of revenues higher or lower than BPA could reasonably expect to receive under average water conditions.

Several comments were received indicating that a specific Federal secondary energy analysis rather than a regional analysis would be a more appropriate and accurate method of determining Federal nonfirm resources and revenues from the sale of those resources. Furthermore, a Federal SEA would more closely indicate the level of sales to the various markets.

For the final Repayment Study, a Federal secondary energy analysis was prepared to replace the earlier method derived from a regional analysis. The new Federal analysis incorporates displacement of short term power purchases and other high cost resources required to serve firm loads, the shifting of firm energy load carrying capability to serve the top quartile of the industries for approximately 6 months of the year, service to the top quartile for the remainder of the year when possible, and the subsequent sale of remaining nonfirm resources to secondary energy markets.

Other comments received on the initial SEA were also accommodated. These indicated some discrepancies between the analyses used in the SEA and in the determination of purchased power for FY 1982. Specifically, a load growth type analysis was made to determine the secondary energy available to displace power purchases, while a no-load growth type analysis was made to estimate secondary energy sales. This inconsistency was corrected. Also, the reduction in secondary available for sale as a result of the shifting of the FELCC was not reflected in the initial revenue forecast because of time constraints. This discrepancy was also corrected in the final revenue forecast.

3. Use of Nonfirm Energy

Nonfirm energy (energy produced from average streamflow beyond critical streamflows) is first used to meet firm load obligations including three quartiles of the DSI loads, resulting directly in a reduction in the need to purchase short term power for a deficit. Next, the extra energy is used to displace high incremental operating cost resources or contracts to the extent they are more costly than the 7(c) rate to the DSI's. Finally, the energy is used to meet the loads of the DSI's not covered by firm resources. The remaining extra energy or nonfirm is marketed at the nonfirm energy rate. This would include operating incremental cost resources for nonfirm markets.

Preference applies to the sale of all Federally generated electric power in the marketing of firm power and separately in the marketing of nonfirm energy. The Regional Act states that the Administrator is expressly deemed to have or must acquire sufficient resources, for all of his firm load obligations, including the loads served under 7(c)and 7(f). Until the Administrator has used all of his available resources to meet his firm load, he has no true secondary or nonfirm energy. If a quantity of power that would otherwise be available to market as nonfirm is necessary to meet the Administrator's firm contractual obligations in the most economical manner, it never becomes nonfirm energy. The Administrator is given the discretion in the Regional Act to determine which resources are used to serve the 7(c) and 7(f) loads. If there is energy available, that would otherwise be nonfirm energy and can be used to displace expensive thermal generation or purchases, or to meet firm loads, the Regional Act requires the use of those resources for such purposes.

In actual operation, when sufficient hydro capability power is available to displace high incremental cost resources and displace all purchases for the deficits that would have occured under critical water conditions, it is generally available in quantities sufficient to meet all such needs. If there is sufficient power, then all such needs would be satisfied. Thus, there is no issue on which resource needs are met in what order. On some occasions there is only enough hydro capability to displace a portion of the power needs. Sound business principles dictate that under these circumstances, the highest incremental cost resources or purchases should be displaced first so that fuel cost savings are maximized for BPA and the Region. BPA makes purchases to cover its firm energy deficit and operates its resources without identifying particular purchases or resources for a particular resource pool. Based on the above information, I believe it is appropriate to assume that available Federal power will be used to maximize the cost savings and assure the greatest reliability for all BPA customers.

In its <u>Brief In Support of Preference for Nonfirm Energy Sales</u> the Public Power Council understandably expresses concern that BPA's proposed operation of its resources to displace expensive thermal purchases for the benefit of all its customers is somehow a repudiation of a 1956 Opinion of the Regional Solicitor (Attached as Exhibit 1 to Exhibit PB 10). As expressed herein, public bodies, cooperatives, and Federal agencies continue to have preference to nonfirm energy (used interchangeably with "secondary energy" herein). We believe that by expanding BPA's firm energy obligations under the Regional Power Act, Congress created additional uses of energy that would otherwise be considered nonfirm for the purpose of meeting needs of the firm loads -- and continued BPA's historic obligation to, overall, keep its rates to consumers as low as possible consistent with sound business principles.

The issue really boils down to whether BPA is obligated to continue to operate an expensive firm thermal resource when power is available to displace that resource, merely for the purpose of creating additional nonfirm energy. Such a practice would, in my opinion, be contrary to prudent utility practice and would defeat my obligation to keep rates overall as low as possible consistent with sound business principles. However, once power is surplus to those firm obligations, nonfirm energy is available. Such nonfirm energy will be marketed in accordance with preference and priority afforded by law: First, to public bodies, cooperatives and Federal agencies within the Pacific Northwest; second, to my other customers in the Pacific Northwest pursuant to the regional preference accorded by Pub. L. 88-552, and third to preference entities outside the Pacific Northwest. Furthermore, when I am able to displace expensive resource purchases, I will likely have abundant nonfirm energy available to satisfy all public body, cooperative, and Federal agency demand for what is truly secondary to my firm power obligations.

A second concern raised by the Public Power Council in its brief was the loss of the benefit to existing preference customers of revenues from the operation of the Federal base system and its ability to generate nonfirm energy. In response to the Public Power Council's analysis, in this final proposal, where the Federal base system is used to generate energy in excess of critical water conditions, to meet firm contractual obligations, including meeting firm loads and displacement of incremental cost resources or purchases, I have credited to the Federal base system revenues equivalent to that which would have been derived from the sale of such power.

4. Conservation Program Effects

In its initial proposal, BPA estimated that a reduction of approximately 150 megawatts in firm energy loads would occur as a direct result of expenditures by BPA on conservation programs either directly or through the granting of billing credits. The total impact of this estimate was not reflected explicitly in the initial revenue forecast.

Representatives of the InterCompany Pool (ICP) suggested that the revenue forecast would be more accurate if BPA adjusted firm loads to account for the impact of conservation programs. This concern is important because the identification of recognizable benefits from expenditures for conservation reduces the forecasted firm energy deficit identified for the public and private utility systems.

BPA subsequently recalculated the costs and anticipated reductions in load associated with each of the programs. Current projected IOU loads already reflect anticipated conservation program benefits, however the programs can now be financed by BPA rather than by the IOU's themselves. However, the projected loads of the public utilities and cooperatives as a whole do not incorporate a load adjustment reflecting the impact of BPA funded conservation programs. Consequently, the projected firm energy loads and revenues associated with the loads of the public utilities have been reduced to reflect the projected conservation that will be realized in their service areas.

The net effect of these changes is to allow the preference customers and IOU customers to use the results of their respective conservation efforts to minimize the need and expense of short term power purchases. The benefits of the conservation actions track through the rates to the customer class causing the benefits.

5. Adjustment of the Firm Energy Load Carrying Capability (FELCC)

Shift of FELCC is an historically proven planning device provided for under the Pacific Northwest Coordination Agreement of 1964 to permit the parties to the agreement to maximize the flexibility of the region's hydro and thermal resources. In general, it is the shaping of reservoir draft from one period to another in order to maximize service consistent with protecting firm loads, yet recognizing the probabilities of greater than critical level streamflows. For planning purposes, the utilities examine all available resources over the critical period. (Critical period is that period of historical streamflows that, when combined with all the reservoir storage will produce the least firm power -- currently about 4 years.) Then the parties take the resultant critical period average surplus and reshape the surplus into the first year, or, in the case of a critical period average deficit, shape the deficit out of the first year to take maximum advantage of the system. There are, of course, practical limits on the extent of this shift that is prudent. In the past, this method of utility operation has permitted an earlier and deeper draft of reservoirs than otherwise would have been possible under alternative methods of operation. If normal or better than average precipitation occurs, and other resources operate as anticipated, the reservoirs refill and the sytem will be able to market energy that otherwise would not have been available to it.

There is a substantial risk that is incurred in a shift of FELCC to deter and consolidate a deficit into a later period if the better than critical streamflows do not materialize. In the event the gamble fails, the utility is faced with a substantially larger deficit in the second, third, and/or fourth years of the critcal period than it would have without the shift. In other words, there is a significant gamble that better streamflows or other load/resource conditions will bail the system out. The utility must find a much greater amount of short-term purchases or restrictable load to meet this deficit -- sometimes beyond reasonable expectations.

Unquestionably, there is some risk involved in a shift of FELCC to consolidate a deficit into a later period. In the past few years, BPA has taken that risk in a very limited sense and shifted its FELCC to cover its identified firm energy deficits in the first year of a critical period. The risk was negligible as a practical matter, however, due in large part to the fact that BPA's loads were consistently underrunning its forecast by a significant amount -- an amount greater than the projected deficit. Furthermore, the extent of the projected deficit was relatively small. Therefore, the maximum potential impact in a later year of the critical period was still small, regardless of the load underrun, and could be covered. Therefore, FELCC was shifted to cover the forecast deficit, the forecast loads were never realized, and the impact and risk of the shift was diminimus.

Comments received from various parties to the rate hearings in the transcripts and in legal briefs maintained that the shift of the FELCC should be made to serve firm loads and thereby reduce and even eliminate the need to purchase power to serve firm energy deficits associated with the Federal base system and new resource pools in the first year of the critical period. These parties argue that sufficient additional resources would be or could reasonably be expected to be available for purchase in the event that reservoirs do not recover so that firm loads can still be met. They recommend that BPA take the risk of future shortages to avoid paying to cover the deficit as you go.

Information was received from the region's utilities indicating which resources would be available for purchase in operating year 1982-83. After assessing whether there was sufficient assurance that these resources could be relied on as firm resources in operating year 1982-83, I determined that there was insuffcient evidence available at the time of this decision to alleviate the risk involved in a shift of FELCC to serve the firm energy deficit for the operating year 1981-82.

Prudent utility practice dictates that a utility should purchase firm resources that are made available to it to reduce any firm energy deficits over the critical period prior to shifting FELCC to cover the deficit in the first year because of the great risk involved in another year. However, if the utility can be assured the availability for purchase of firm energy resources of sufficient quantity in the second, third, and/or fourth years of the critical period to meet firm loads in the event that its reservoirs will be usable for that purpose, then a shift of FELCC to cover the firm energy deficit is merited. In fact, it is not so much a shift of deficits as a shift of FELCC to accommodate purchased resources in the later years of the critical period.

The Regional Act establishes that BPA has an obligation to acquire sufficient firm resources on a planning basis to meet its firm loads, including three quartiles of the DSI loads. BPA must make the necessary short-term purchases to satisfy that requirement for the critical period. In the extreme, the net effect for the critical period this rate year could be to shift FELCC to place the entire deficit in the first year if resources were available and could be purchased. Again, there is not sufficient evidence that adequate resources are available to warrant such an action. Furthermore, the consequences would be to distort the risks and costs of purchases between years of the critical period.

In developing the final rates, a reduction has been made to the load forecast to bring it in line with the actual trend. I view the firm energy deficit that has been identified for the critical period as an accurate deficit, and, therefore, the risk involved in shifting FELCC to cover this deficit cannot be mitigated by an expected load underrun. I feel that the size of the deficit is so large that, if shifted to a subsequent year in the critical period, it cannot reasonably be tolerated. While the probability of actual streamflows being substantially better than critical is high, and there is some probability of obtaining adequate short-term power purchases to cover the shifted deficit in later years, the risks remain unacceptably high in view of the consequences. More importantly , the probability of power being actually available through better streamflows and power purchases not yet obtained are equal in each year of the critical period. Therefore, BPA has established its FELCC in a manner to uniform the deficit over the critical period and thus uniform the risk. BPA will then utilize its purchase authority under the Regional Act to purchase resources to meet these otherwise anticipated firm load deficiencies. An estimate of the costs associated with this purchase has been included in the Repayment Study.

6. Firmness of Top Quartile

Service to the DSI's under the Regional Act is for power subject to limited interruption for service to the Administrator's other firm loads. As part of this service BPA is to plan and acquire sufficient firm resources to satisfy three quarters of the DSI load. The remaining one quarter is commonly referred to as the DSI "Top Quartile." This top quartile is to be treated as a firm load for operating purposes only. We give effect to this direction by shifting some FELCC under the Pacific Northwest Coordination Agreement, and using energy available to BPA in excess of other firm power needs as covered above.

In the revenue forecast used in the Repayment Study submitted to the parties in late April, it was assumed that the top quartile of the DSI load would be served for approximately 6 months of the operating year with shifted FELCC to the extent necessary. It was also assumed that any energy available to the Administrator after meeting BPA's firm energy deficits including displacing purchases and high incremental cost resources would be used to provide service to the remaining top quartile load of the DSI's. Any such energy remaining after meeting all of BPA's firm obligations would then be available for sale under the NF-1 nonfirm energy rate schedule to markets in both the Pacific Northwest and the Pacific Southwest. These particular assumptions were made by BPA in accordance with our interpretation of the Regional Act and its legislative history.

Concern has been raised by representatives of the region's private and publicly-owned utilities as to (1) whether and to what extent under the Regional Act is service to the top quartile of the DSI's firm is nature, (2) whether and to what extent utilization of nonfirm energy to serve the top quartile violates the preference and priority provisions of the Bonneville Project Act, and (3) whether the proposed shift of FELCC to serve the top quartile violates the Pacific Northwest Coordination Agreement.

There is disagreement between the parties as to the interpretation of the language of the Regional Act and the legislative history that focuses on the top quartile and the quality of service it is to receive. The DSI's maintain that service to the top quartile is a firm obligation but with a lower quality -- a "junior firm" type of firm power. BPA's other customers, particularly public bodies and cooperatives, claim that service to this portion of the DSI load is in fact nonfirm power that is subject to preference and priority provisions of the Bonneville Project Act and the Regional Act. My position is that the top quartile of the DSI load is a type of firm load but is not served with either firm or nonfirm power. Instead, the top quartile is a quasi-firm load, to be served by operating resources in such a manner as to produce a quantity of power with firm characteristics, while not installing additional resources to meet it on an absolute firm basis. In effect, it results in planning to meet regional loads on better than critical water with the benefit and risks going to the DSI's.

The Regional Act establishes the quasi-firm status of the DSI top quartile. Sales to the DSI's by virtue of Section 5(d)(1)(A) are to "provide a portion of the Administrator's reserves for firm power loads." The Regional Act defines reserves as the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers. Service to the top quartile cannot be restricted to provide service to nonfirm loads or to make sales of nonfirm energy. I view the top quartile as providing a reserve for the Administrator's firm load obligations. Therefore, I have determined that the proposed utilization of energy above critical streamflows to serve the top quartile before marketing as nonfirm does not violate any preference or priority provisions awarded the public bodies and cooperatives, but rather is service mandated by the Reqional Act and its legislative history. Nevertheless, in the rate design, we have assigned costs to the DSI's for this power at the average expected revenue from nonfirm sales and have distributed the revenues back to the Federal base system and new resource pools.

The Regional Act not only does not preclude the Administrator from serving the top quartile of the DSI load by shaping the FELCC, but explicitly discusses it in the legislative history. The objective, however, is not the shifing of FELCC, but a maximum average availability of service commensurate with the risks involved. Admittedly, there are alternative means to accomplish the same objective. For example, a combination of FELCC plus the use of Advance or Provisional energy and flexibility in the use of FELCC may better satisfy the objective. In the proposed shift or any other approach to serve top quartile loads, the DSI's are required to assume all of the risks, as well as receive the benefits of improved quality of service, such that the firm loads of the Administrator are protected from any impact of the shift.

The shift of FELCC for service to the top quartile is, in reality a shift of DSI firm load from a later year in the critical period to the first year. As a result the DSI's expose to interruption a comparable portion of their load in that later year. The rights of BPA to restrict the top quartile, however, remain in all years. It was pointed out in the record that the objective of maximum availability to the DSI's was not served by a shift of FELCC for the entire year, but should only be made, if at all, until streamflow information is available - - usually around January 10 of each year. The studies were adjusted to conform with this position.

In practice, BPA will first utilize its purchase authority under the Regional Act to purchase resources to meet otherwise anticipated firm load deficiencies, including three quartiles of DSI load. Second, it will shift the FELCC to cover any deficit that could not be covered by purchases at a resonable costs consistent with acceptable risks and then will shift the FELCC to serve, to the extent practicable, the DSI top quartile for the early portion of the operating year. If the reservoirs refill as anticipated, the DSI top quartile has been served under operations as if it were firm and the region is better off. If the reservoirs do not refill, the service to the DSI's top quartile is restricted and an equivalent amount of power is pulled back from the second and third quartiles in later periods to compensate for the borrowed FELCC.

7. Escalation

The Repayment Study supporting the initial power rate proposal used a 12-percent escalation rate based on an analysis of the information available to BPA in February 1980. Representatives of the ICP questioned whether or not an analysis had been undertaken to support the appropriateness of a 12-percent escalation rate. The escalation rate, as well as the interest rate for bonds issued during the test year (July 1, 1981-June 30, 1982), 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, since information in these areas becomes outdated quickly.

BPA reviewed escalation rates again in April 1981 to determine whether a revision of the assumed escalation rate was appropriate for the final Repayment Study. I determined that this change was appropriate and decided that the Gross National Product deflator rate from the FY 82 Budget was the most appropriate rate to use at that time. This is because the GNP deflator is widely used by the Federal government and is representative of several other similar indices that might be used. Consequently, I have directed the staff to use escalation rates for FY 81 and FY 82 of 10.5 percent and 9.3 percent, respectively, as the escalation rates for the final Repayment Study. While the revised FY 82 Budget adopts the Gross National Product deflators of 9.9 percent and 8.3 percent (Exhibit IP-SR-13) I conclude that deflators are overly optomistic for an electric utility and I adopt the original deflators based upon past inflation experience in the utility industry exceeding economic indices (Transcript, p. 4768 and 4786).

8. Washington Public Power Supply System (WPPSS)

The Repayment Study supporting the initial power rate proposal included the costs of bonds issued for WPPSS Nuclear Project Nos. 1 and 2 after July 1, 1982. Several comments suggested that the Repayment Study should exclude costs for WPPSS Nuclear Projects Nos. 1 and 2 that occur beyond the test year. Inclusion of additional facilities beyond the test year would increase the costs assigned to the Federal base system resource pool, resulting in higher rates to BPA's public agency customers as well as the residential customers of the region's IOU's.

V. Long Run Incremental Cost Analysis

A. Introduction

The Long Run Incremental Cost (LRIC) Analysis is a cost-of-service analysis focused on incremental costs either incurred to meet load growth requirements or saved by not meeting an additional increment of load. This differs from an embedded cost-of-service analysis that is conducted primarily to reflect the book costs that the utility is required to recover, based on its particular accounting practices.

The LRIC approach is a method of applying the principles of marginal cost pricing to electric rates, given the constraints under which utilities must operate. The first step of the LRIC Analysis consists of determining how the system would react to changes in loads and then collecting the necessary data to measure the corresponding effect on total costs in the resulting LRIC Analysis. 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 LRIC 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 LRIC Analysis provides the basis for the classification of certain generation costs between capacity and energy in the COSA and in the development of illustrative LRIC rates. Application of the rates would provide information to consumers enabling them to make informed consumption decisions based on the costs to society of providing electric power.

B. Generation

1. Capacity

The LRIC of generation is divided between capacity and energy costs. The LRIC of capacity is based on the additional resources added to the system to meet peaking requirements. For the FCRPS, peaking requirements will be met by additions of peaking units and existing hydro plants (a total of 12 projects with 7,226 megawatts of generation capacity by the year 1989). Annualized investment costs, annual operation and maintenance expenses, and annual replacement costs (all expressed in FY 1982 dollars) divided by the nameplate capacity adjusted for a reserve factor produces a dollars per kilowatt LRIC of capacity. The long run incremental cost of capacity for BPA is $55.32 per kilowatt (Table 1, LRIC).

Many comments have been received regarding the LRIC of capacity. Some of the comments indicated that BPA should not include certain peaking units in the LRIC Analysis for the following reasons: (1) they would be embedded units by test year FY 1982; (2) they would be of such a uniquely high or low cost that the LRIC of capacity would be biased and an unstable estimate would be created, and (3) because facilities necessary to obtain peaking from a given unit had not been authorized by Congress.

The procedure used to develop the LRIC of capacity is to determine a generic hydro peaking addition representative of the incremental cost of capacity. The LRIC of capacity is developed by averaging the cost of hydro peaking units currently on the Federal system or planned through FY 1989. The cost averaging technique is used because each of the peaking units is unique and no single unit's cost represents typical costs or the LRIC of capacity to BPA.

In the initial proposal, BPA selected a hydro peaking facility planning horizon of FY 1980 through FY 1989. This reduced the number of peaking units used in the initial LRIC Analysis relative to the 1979 LRIC Analysis that considered all existing hydro peaking facilities on the Federal system as well as those to be added through FY 1986. For the final LRIC Analysis, the number of peaking units included for determination of the LRIC of capacity has been expanded to include all existing and planned peaking units through FY 1989. This expansion increases the sample size and leads to increased stability in the LRIC of capacity. While a number of these units are already operational, their costs are escalated to FY 1982 dollars as an indication of what those units would cost if constructed during FY 1982.

Another issue that has been raised concerns the appropriate value for the energy produced by the hydro peaking units. Of the hydro peaking units analyzed by BPA in the initial proposal, only Bonneville Second Powerhouse and Libby Reregulating Dam will produce incremental firm energy. The other hydro peaking units will merely shift the timing of the energy delivered instead of producing incremental energy. Consequently, the issue of valuing the energy associated with the use of these facilities does not arise. Incremental firm energy will be produced by the Bonneville Second Powerhouse because of the hydraulic imbalance resulting from upstream projects. However, this incremental energy can be entirely produced by four of the eight units. Furthermore, if the units at the Libby Reregulating Dam are excluded from the analysis, no firm incremental energy will be produced at Libby units 5-8. Consequently, for the final LRIC Analysis, four of the Bonneville Second Powerhouse units and the Libby Reregulating Dam units are excluded from the LRIC of capacity determination. This change ensures that only those units considered to be entirely peaking units are included in the LRIC of capacity determination.

Other comments were received concerning BPA's assessment of items in the determination of the LRIC of capacity such as tailwater restrictions, river regulation benefits, downstream effects, streambank stabilization costs, the cost of energy used for pumping in pump generation units, and costs related to headwater loss from the use of peaking units. Tailwater restrictions were considered, and stabilization and reinforcement costs are included in the LRIC Analysis. Energy used for pumping associated with pump generation units was not considered because BPA analyzed only those costs that must be repaid through revenues. The other costs and benefits are difficult to quantify and will require further study before they can be included. However, BPA does agree that all costs and benefits should be assessed in determining the LRIC of capacity.

In the initial proposal and the 1979 LRIC Analysis, BPA indicated that while combustion turbines were the traditional least cost source of peaking capacity for utilities in general, hydro peaking units were selected by BPA to determine the LRIC of capacity. The rationale being that BPA did not have the authority to acquire combustion turbines and that hydro units were already being constructed to meet the increase in peaking demands. As a backup to the initial proposal, an LRIC analysis of a simple cycle combustion turbine was made as a way of determining the difference between the cost of a combustion turbine and a hydro peaking unit. The analysis indicated that the costs were not significantly different with combustion turbines being the higher cost of the two.

With the passage of the Regional Act and BPA's new resource acquisition authority under the Regional Act, the combustion turbine issue received significant comment during the hearing process. The comments were directed to BPA's LRIC analysis of a simple cycle combustion turbine. The comments indicated the following: (1) the reserve factor used was inappropriate; (2) the price of oil was low; (3) the capacity factor was high; (4) the interest rate used to capitalize investment was high; (5) the energy produced while using the combustion turbine should be valued; and (6) the cost of a combustion turbine should be used by BPA as the basis for the LRIC of capacity.

The reserve factor applied in the combustion turbine analysis was developed for the LRIC analysis of capacity. This factor was not intended to be resource specific but to represent the reserve factor that would be applied to an additional increment of generating capacity regardless of the source of the capacity. It is agreed that the portion of the reserve factor related to the hydro realization adjustment is not appropriate for analyzing a combustion turbine and, consequently, it has been excluded from the reserve factor used in the combustion turbine analysis for the final proposal.

Concerning the price of oil used in the analysis, it is agreed that the price developed for the analysis did not accurately reflect the current projected market prices for the test year. The oil price data submitted in testimony by the Public Generating Power Pool and Snohomish County PUD has been used as the basis for the oil price used in the final combustion turbine analysis. The average price for 1980 has been escalated to 1982 dollars using BPA's current estimate of escalation.

I disagree with the argument that a 1.5 to 2 percent plant factor is appropriate for a combustion turbine cost analysis for BPA. It is probable that for BPA's predominately hydro system, combustion turbines would be block loaded and some hydro peaking facilities would be used for the periods of extreme peaks. Further, the operating characteristics and capability of the hydro system, as well as the duration of the system peaks, imply that a combustion turbine peaking unit would have a capacity factor larger than 1.5 to 2 percent. The capacity factor used in the final analysis is 7.5 percent. This rate is supported by the FERC that recommends use of a capacity factor of 7.5 percent for combustion turbines when evaluating hydroelectric power.

In the LRIC analysis of the combustion turbine, the interest rate applied to the capital cost was 12 percent. This rate represents the incremental rate at which BPA can borrow money from the U.S. Treasury. The analysis assumes that BPA would be funding the combustion turbine and, consequently, the 12 percent rate of interest is the appropriate rate.

It is appropriate to provide an energy credit to the cost of a combustion turbine. Since the combustion turbine produces incremental energy, the appropriate price for this energy is the LRIC of energy. The credit would not be a subtraction of the fuel cost from the total cost, since the combustion turbine must be operated in order for capacity to be provided. However, there appears to be a point at which continued operation of the turbine would be for the purpose of providing energy and that a credit is needed to offset these costs. To determine the energy credit, an iteration process was used. This resulted in an energy credit of 60.8 mills per kilowatthour applied to the variable costs of the simple cycle combustion turbine for the final analysis (Appendix, LRIC).

With the energy credit applied, a 7.5 percent capacity factor, the higher fuel cost, and the revised reserve factor, the LRIC of a combustion turbine is $61.09 per kilowatt (Appendix, LRIC). This result supports BPA's use of the chosen hydro units to determine the LRIC of capacity of $55.32 per kilowatt. Given the many necessary assumptions that were required to produce these results, they are very close. However, the cost based on hydro peaking units is lower, supporting them as the least cost peaking option available to BPA. BPA staff will continue to refine study results to assure that the best available information is used in future rate filings.

2. Energy

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 for further hydroelectric development to produce energy. 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 are currently 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 (WPPSS) 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 61.76 mills per kilowatthour (Table 3, LRIC).

BPA received several comments on the LRIC of energy determination. Some comments indicated that BPA should base its LRIC of energy determination on the costs of WPPSS Nos. 4 and 5 instead of WPPSS Nos. 1, 2, and 3, or if not WPPSS Nos. 4 and 5, then WPPSS No. 3 should be the only unit used.

BPA used the costs of WPPSS Nos. 1, 2, and 3, adjusted to FY 1982 constant dollars and averaged over the three units, as the basis for the LRIC of energy. In this way, BPA developed costs for a representative additional thermal baseload plant. The representative plant is an "average" of the technologies contained in WPPSS Nos. 1, 2, and 3. It would not be appropriate to select one plant and assume that it represents the costs of a generic plant available to BPA in the future.

Other comments concerned the costs included by BPA for the LRIC of energy determination. It was recommended that BPA include the waste disposal, decommissioning, and environmental costs related to nuclear power production facilities.

BPA agrees that all quantifiable costs related to a facility should be included in the LRIC determination. Certain costs such as waste disposal and environmental costs will require further study before they can be included in the LRIC Analysis. Comparable costs are not included with BPA's other generation costs. However, for the final LRIC Analysis, BPA has included projected costs for decommissioning WPPSS units 1, 2, and 3 in the determination of the LRIC of energy. (Table 3, LRIC).

BPA received comments indicating that the capacity factor used in the LRIC of energy analysis was high in relation to actual capacity factors for operating nuclear plants and that the interest rate used to capitalize the investment was low. The capacity factor used by BPA is an average rate based on a capacity factor of 65 percent for the first three years and 70 percent for the remaining life of the facility. These values are specified for use in planning by the Pacific Northwest Coordination Agreement and, thus, are used by BPA.

The interest rate used by BPA for the WPPSS projects in the initial proposal was based upon dated projections of coupon rates for future WPPSS bonds. For the final proposal, the interest rate is increased from 7.25 percent to 11 percent. The higher rate is based on an analysis of the current long term bond market and represents a long term incremental interest rate.

A number of other comments were received concerning the procedure and rationale behind the LRIC of energy determination. It was argued that marginal energy costs should be based on the short run variable costs of producing the last increment of energy on the system. That is, in general, incremental costs should be based on short run considerations instead of the long run.

BPA has considered the use of short run measures of incremental cost. Short run costs are more unstable 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 on incremental cost analyses.

C. Transmission

The LRIC of transmission is based on additions to transmission investment through 1989 plus annual operation and maintenance expenses associated with new transmission facilities. The analysis of incremental transmission costs includes the segmentation of those costs between main grid reinforcement and generation-integration. Reinforcement costs are those costs incurred to strengthen the transmission system to accommodate new loads and resources. 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 and non-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 transmission reinforcement costs represent capacity costs only.

The long run incremental annual cost per kilowatt of BPA's transmission reinforcement system is $49.02 (Table 6, LRIC). Generation-integration transmission annual costs per kilowatt include both a capacity and an energy component. The Federal generation-integration incremental annual capacity cost per kilowatt is $3.63 (Table 7, LRIC) and non-Federal generation-integration incremental annual capacity cost per kilowatt is $1.91 (Table 8, LRIC). Annual transmission generation-integration energy costs are expressed in mills per kilowatthour. The annual Federal and non-Federal generation-integration incremental energy costs are .27 mills per kilowatthour and 1.09 mills per kilowatthour, respectively (Table 11, LRIC).

A few comments were received concerning the determination of the LRIC of transmission. One comment noted that between the 1979 LRIC Analysis and the 1981 initial LRIC Analysis, additions to transmission system peak load fell approximately 50 percent and the costs associated with the additions fell only 6.5 percent. This was felt to be inappropriate for LRIC purposes.

BPA examined the transmission plant investment data used in the LRIC of transmission analysis, and modifications and reductions to the total amount of investment were made (Table 4, LRIC). These reductions helped lower BPA's estimate of the LRIC of transmission reinforcement capacity (Table 6, LRIC). It also was determined that the FY 1980 through FY 1982 Federal generation integration investments are related to numerous projects and, consequently, have been removed from the final LRIC Analysis (Table 7, LRIC).

BPA also considered the comment that it was incorrect to use the discounting procedure in the determination of the LRIC of transmission capacity because the procedure treats transmission, a real asset, as if it were financial asset. I believe that discounting additional transmission capacity and costs is a way of distributing additions to transmission investment over a given time period. This provides BPA with a useful way of determining annual levelized transmission investment per unit of load growth in real terms.

D. Rates

The results of the LRIC Analysis were used to develop rates for test year FY 1982. 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 in the calculation of illustrative demand charges (Table 12, LRIC) was the quantification of the total long run incremental capacity cost. It was determined that the long run incremental cost of generation capacity was \$55.32 per kilowatt (Table 1, LRIC) and transmission reinforcement capacity was \$49.02 per kilowatt (Table 6, LRIC). The charge per kilowattmonth for capacity purchases would be \$4.24 for generation plus \$3.47 for transmission reinforcement plus \$0.28 for Federal generation-integration, for a total of \$7.99. The non-Federal generation-integration charge is \$0.12. The generation and transmission components were calculated separately because wheeling customers would pay only for the transmission component.

The energy charge for generation is 61.76 mills per kilowatthour (Table 3, LRIC). The energy charge for transmission Federal generation-integration is .27 mills per kilowatthour (Table 11, LRIC) and 1.09 mills per kilowatthour (Table 11, LRIC) for non-Federal generation-integration.

The basic LRIC rates were time-differentiated in the TDPA. The result of this analysis is that the LRIC of generation capacity (\$55.32/kW-yr) is assigned to the peak period of December through May, Monday through Friday, 7 a.m. to 10 p.m. at a rate of \$8.54 per kilowattmonth. Federal and non-Federal generation- integration capacity costs also are assigned to the peak period at a rate of \$0.56 and \$0.25 per kilowattmonth, respectively. Transmission reinforcement capacity cost is assigned over the entire year, Monday through Friday, 7 a.m. to 10 p.m. at a rate of \$3.47 per kilowattmonth. It was determined in the TDPA that LRIC energy charges would not be time-differentiated and are therefore the same rate for peak or off-peak periods.

E. Motion to Exclude

A motion and memorandum has been submitted by the Public Generating Power Pool (PGPP), the Public Utility District of Snohomish County, and the Oregon People's Utility Districts. The motion is to exclude certain comments in the Staff Evaluation of the Official Record concerning three LRIC topics I discussed in Section B(1), a comment on contract negotiations concerning restriction rights, the transformation charge discussion, and to exclude from the Official Record BPA's legal brief noted in the Staff Evaluation. While this motion and memorandum concerns several topics, I have decided to comment on the motion in its entirety at this point in the decision document.

The Hearing Officer ruled that the Administrator could make the decision on how to treat this motion. I have decided to grant the motion to exclude the comment on contract negotiations concerning restriction rights and the transformation charge discussion from the Official Record. Specifically, the following portions of the Staff Evaluation are excluded:

1. Page 67, first full paragraph - the third sentence;

2. Page 84, paragraph 5 and paragraph 7 which continues to the top of page 85;

3. Page 85, first full paragraph and paragraphs 3 and 4.

Several of the parties expressed surprise that BPA Counsel filed a brief at the same time as the other parties. Two related allegations can be identified:

1. It simply was not contemplated that BPA would file a brief (see e.g. PGE Response to Evaluation at 1).

2. BPA's filing of a brief contemporaneous with the other parties deprived the parties of an opportunity to respond (see e.g. PGPP brief at 3).

As to the first concern, there are several places in the record that BPA's Counsel announced his intention to file a brief contemporaneous with the parties. The issue first arose formally upon the motion of Mr. Meek to be allowed to file a final brief (Transcript, p. 969). In argument regarding Mr. Meek's motion, Mr. Dotten, BPA's Counsel said on March 31, 1980:

"MR. DOTTEN: Well, Your Honor, I don't believe I've taken a position against the filing of briefs. I've thought all along that the legal issues in this proceeding probably would best be handled by the filing of briefs; and although you're quite correct, the procedures don't that I can see provide for briefings, nevertheless I think that certainly would be in your discretion, and if you believe it would be of aid to youself in analyzing the record and of aid to the

Administrator, I think it would be appropriate that the parties do file briefs. We would like that opportunity." (Transcript, pp. 1157-1158).

The transcript continues:

"JUDGE RATZMAN: Well, the briefs of which parties under your proposal would come in on the 17th of April?

"MR. DOTTEN: The briefs of any parties wishing to file briefs, Bonneville included." (Transcript, p. 1159)

While the dates changed due to extensions of the hearings, the process for filing briefs remained as described in the transcript, parties wishing to orally argue did so first and filed a shorter brief contemporaneous with the other parties, including BPA. Thus it is clear in the record that BPA Counsel would file a brief and at the same time as the other parties.

The second concern relates to the argument that the contemporaneous filing of the BPA brief deprived the parties of knowledge of BPA's positions as to the law. This argument should be weighted against the fact that virtually all issues addressed in BPA's brief were addressed at length by the other parties in their briefs. This is because BPA's position on all issues in the case was thoroughly explored and developed in the rate hearings. I find that the contemporaneous filing of BPA Counsel's brief did not deprive any party of a full and fair opportunity to argue their case to BPA. I therefore expressly deny the motion to exclude the BPA Counsel's memorandum from the record.

I have considered the comments in the motion and memorandum to exclude reference to the 1979 LRIC Analysis in the Staff Evaluation. I have decided to continue to include the references primarily because the 1979 LRIC Analysis is an official BPA publication. References to the 1979 LRIC Analysis were made in the hearings (Transcript, pp. 404-405, 1198, 1365; Exhibit SC-2, p. 7) which further supports my decision to include the document.

The motion and memorandum also indicates that reference in the Staff Evaluation to the use of Libby units 5 - 8 as peaking capacity without the reregulating dam should also be excluded from consideration. Support for the statement that streamflows will at times be high enough for Libby units 5 - 8 to provide capacity without the reregulating dam is contained in the record (Exhibit DS-4, Exhibit 2). The indication is that on the average, Libby units 5 - 8 can be expected to provide capacity during 1 month of the year and at a maximum, for 5 months. The primary support for my use of Libby units 5 - 8 as peaking units is the fact that BPA includes these units as peaking units in its long-range plans. These plans are supported by the Pacific Northwest Utilities Conference Committee's document titled <u>Long-Range Projection of Power Loads and Resources for Resource Planning</u> (the "Blue Book"). Table 4 of this document indicates that Libby units 5 - 8 are scheduled for service and Table A-3 indicates that the units are determined to provide capacity only. The "Blue Book" was cited extensively on the record and the Libby Reregulating Dam issue was also discussed (Transcript, pp. 1355-1358).

The motion and memorandum indicates that the discussion concerning the exclusion of four of the Bonneville Second Powerhouse units and the Libby Reregulating Dam units contained in the Staff Evaluation should be excluded. I do not agree with this motion. Statements are made on the record concerning the hydraulic imbalance and the decline in spillage resulting from the Bonneville project (Transcript, pp. 1204 and 1343). It is also indicated on the record that four of the Bonneville Second Powerhouse units provide only capacity (Transcript, p. 1345; Exhibit B, Exhibit 2, Table 1). Exclusion of the units at the Libby Reregulating Dam is supported by the fact that BPA does not include them in its long-range resource plans. Further support is provided in the "Blue Book" where the units at the Reregulating Dam are identified as prospective resources only (Table 7) and the units are not included in hydro resource projections through the year 2000 (Table A-3). Thus, except as expressly granted, the PGPP's motion to exclude the staff evaluation from the record is denied.

VI. Cost-of-Service Analysis

A. Introduction

The purpose of the Cost-of-Service Analysis (COSA) is to determine the cost of providing service to various classes of customers and to provide a basis for evaluating the adequacy of the current wholesale power and transmission rates. The COSA also enables BPA to conform to the requirement of Section 10 of the Federal Columbia River Transmission System Act that "the recovery of the cost of the Federal Transmission System shall be equitably allocated between Federal and non-Federal power utilizing such system."

The analysis performed in the COSA consisted of four basic steps. The first of these was functionalization. This portion of the process consisted of grouping investment and operating costs into the functions of generation, transmission, and metering and billing (Tables 9, 14, and 20, COSA). The assignment of these costs was based on a direction of effort study (Exhibit 1, COSA) that determined the facility and operating expenses properly assigned to each of the three functions.

The second step in the COSA process consisted of classification. Classification refers to the process by which costs are assigned to either capacity or energy (Tables 10, 15, and 21, COSA).

Segmentation was the third step in the COSA process. To better assure an equitable allocation of the costs of the transmission system among all classes of service, the transmission system was divided into seven segments (Tables 11 and 16, COSA). The costs of each segment could then be identified separately and allocated in relation to the service provided (Tables 12 and 17, COSA).

The final step was the allocation of all costs to the classes of service (Tables 3, 13, 17, and 22, COSA). A monthly peak responsibility method (12 CP) was used in allocating capacity costs to the various customer classes (Table 19, COSA). The allocation of costs classified to energy was in direct proportion to the kilowatthours of energy associated with each class of service (Table 19, COSA).

Both the Repayment Study and the LRIC Analysis logically precede the COSA in the rate development process. BPA's revenue requirement is based on a Repayment Study. The proportionate cost relationships identified in the COSA for classes of service were applied to the revenue requirement determined in the Repayment Study. Furthermore, because a long run incremental cost causation approach to classification was used, it was necessary to complete the LRIC Analysis prior to completing the classification portion of the COSA.

B. Functionalization

Concern was expressed over BPA's basis for functionalization of the IOU exchange resources (Table 20, COSA). The basis for this concern was that BPA's method relied on a preliminary average system cost methodology that is subject to revision. Although the preliminary average system cost methodology is subject to revision, it was based on the FERC's (FERC) Uniform System of Accounts, functionalized cost data reported on FERC Form 1, and on appropriate functionalization procedures. I therefore decided that the preliminary average system cost methodology represents the best available basis for the functionalization of the exchange resources.

C. Classification

Once all costs were functionalized, those assigned to generation were classified to generation capacity and energy production. Transmission costs were classified entirely to capacity. The classification of generation costs was based on the principle of cost causation. This method apportioned generation costs between capacity and energy in relation to the reasons underlying the construction and operation of various generating plants. The cost of facilities constructed to meet peaking capacity was classified entirely to capacity and the cost of facilities that provide both capacity and energy was apportioned between the two functions.

Since differences exist in the purpose and operation of hydro facilities versus thermal plants, separate classification approaches were used for these types of facilities. It has been suggested that this bifurcated approach to classification is inappropriate. I disagree with that position and consider the approach taken to be a legitimate reflection of characteristic differences between the hydro and thermal plants comprising BPA's generating resources.

The DSI's argued for application of a fixed/variable method to all generation costs. This would result in classification of fixed costs to capacity and variable costs to energy. Such an approach would result in classification of virtually all of BPA's costs to capacity. The DSI's pointed out that this would produce rates similar to the demand-only rates employed by BPA prior to 1974 and that high load factor customers who are imposing little or no load growth on the system would not be forced to bear an inappropriately large proportion of BPA's costs.

Other parties have suggested that a fixed/variable approach would provide a more objective and more reliable basis for classification than the approaches employed by BPA. It was also suggested that such an approach would improve BPA's revenue stability. This reasoning was based on the assumption that capacity requirements are less sensitive to temperature fluctuations and can be more reliably forecast than energy requirements.

I reject the use of the fixed/variable approach for several reasons. In the short run, all the costs that do not vary as output varies 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.

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 a capacity and an energy component 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 the negligible variable costs of hydro plants.

Regional growth has promoted almost full development of cost effective hydro sites. Thermal generation is being constructed to produce significant amounts of base load energy, while peaking requirements are being 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, although these plants also provide capacity.

I believe there is no reason for BPA to base the adoption of a fixed/variable approach on the fact that it would produce rates similar in design to those in effect prior to 1974. BPA did not have the benefit of having a fully allocated cost-of-service analysis available for use in designing rates prior to 1979.

The argument by the DSI's that high load factor customers are bearing the cost of load growth for which they are not responsible is inappropriate. Although some of BPA's high load factor customers are imposing little or no load growth on the system, they still require service that must be provided by increasingly expensive energy generating resources.

I recognize that a fixed/variable approach utilizes historical data that may be more reliable than the data projections employed in a cost causation approach. In either case, however, a number of necessarily subjective decisions must be made in arriving at the resulting classification percentages. Questions of objectivity are present in both approaches. I believe BPA has achieved a reasonable degree of reliability in the approach to classification and that the approach is more valid than a fixed/variable approach would be. The potential error associated with questions relating to objectivity and reliability is greatly exceeded by the failure of a fixed/variable approach to appropriately reflect the operational and planning characteristics of the FCRPS.

The problem with a fixed/variable approach is that it considers classification of capacity and energy strictly from an operational standpoint and completely disregards a cost causation or planning approach. FERC, in its remand order concerning BPA's 1979 rates, has indicated general support for the classification scheme.

1. Hydro Classification

Several concerns have been raised specifically with regard to the method BPA applied to the classification of hydro facilities. Several parties have suggested that BPA's equal allocation of the costs of baseload hydro facilities to capacity and energy is arbitrary as well as inconsistent with the actual operational characteristics of the hydro system. The DSI's have suggested that the hydro classification method of the National Association of Regulatory Utility Commissioners (NARUC) would offer BPA a theoretically sound method that would produce results similar to those arrived at under BPA's method.

I disagree that the method applied to baseload hydro is arbitrary and without theoretical justification. I believe an equal division of baseload hydro costs between capacity and energy accurately reflects the services provided by those facilities. The fact that the plant factor of the baseload hydro facilities is less than 100 percent under critical water conditions does not alter my conclusion. The lower load factor is a function of the need to shape resources to meet load and would not be a basis for increasing the proportion of cost assigned to energy.

I believe the rationale for the NARUC method for classification is unclear. An implicit assumption underlying this method is that average megawatts produced under critical water conditions represent the allocation for capacity while the difference in average megawatts between this output and output under median water conditions represents the allocation for energy. While the rationale for the method is not explained in the NARUC cost allocation manual, it appears average megawatts under critical water conditions represents dependable capacity and the difference between that figure and average megawatts under average water conditions represents energy.

BPA 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 the resources that are available to meet those loads under critical water conditions. The method referenced in the NARUC cost allocation manual treats the cost of the 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. I do not believe that the method described by NARUC is appropriate for the FCRPS. The NARUC cost allocation manual acknowledges that the method would only apply to that portion of the system that is baseload. A significant portion of BPA's hydro resources are used for peaking and produce no incremental energy.

In addition to concerns over the method applied to baseload hydro facilities, the proposed assignment of 100 percent of the costs of hydro peaking units to capacity has been challenged. It was suggested that the cost of capacity capability beyond that necessary to generate critical energy should be classified to energy and allocated to nonfirm, the argument being that it is this capability that enables the production of nonfirm energy.

I believe that it is inappropriate to allocate any costs to the production of nonfirm energy because no costs have been incurred for this purpose. Therefore, it would be inappropriate to classify any hydro peaking costs to energy for this reason. Peaking facilities enable BPA to shape resources to meet firm power loads in a maximally efficient manner. Furthermore, because of the storage capability of the FCRPS, in the absence of capacity requirements, those units BPA has identified as baseload facilities would be capable of capturing an energy potential greater than that represented by BPA's highest water year of record. Therefore, I conclude that these peaking units serve the function of meeting firm capacity requirements rather than nonfirm energy loads.

2. Thermal Classification

Several concerns have been expressed that apply directly to the method BPA has employed to classify thermal resource costs. The DSI's have suggested that it is arbitrary to assume that the long run incremental cost of energy is equal to the total cost of thermal resources minus the lowest alternative cost of capacity. They suggest a reverse procedure (using the lowest alternative cost of energy) would be equally defensible. They further suggest that it is inappropriate to assume that capacity provided by hydro facilities is comparable to that provided by thermal facilities. They attempt to make the point that thermal plant capacity is less subject to availability problems than hydro capacity and, presumably, of greater value.

I disagree with these positions for the following reasons. First, it is not possible, in the absence of theoretical assumptions, to isolate energy costs from capacity costs. Any facility that produces energy will also produce incremental capacity. It is possible, however, to isolate capacity costs from energy costs. BPA's hydro peaking facilities produce capacity without producing incremental energy.

Second, BPA has acquired the output of thermal resources because of growth in the demand for energy. I recognize that these thermal resources also provide capacity; however, if BPA needed to increase only its capacity resources, it would not be economically prudent to acquire such capacity from thermal resources. Rather, BPA would acquire capacity at the lowest possible cost. Analyses performed by BPA, in response to suggestions that BPA consider the appropriateness of using combustion turbines, have confirmed the initial position that hydro peaking facilities represent BPA's lowest cost alternative for capacity.

Finally, I reject the idea that capacity provided by hydro facilities is an inappropriate proxy for capacity provided by thermal resources. Given the storage facilities of the FCRPS, the availability of hydro peaking capacity is comparable to or better than that of thermal peaking resources. Furthermore, hydro capacity is significantly more flexible than thermal capacity. This characteristic makes it particularly valuable in enabling BPA to shape resources to meet loads.

For the foregoing reasons, I believe BPA has employed an appropriate method in arriving at the long run incremental cost of energy from thermal resources. I also affirm the application of this cost result in developing the classification of thermal resource costs and believe it to be consistent with a cost causation approach to classification. As I indicated in the first portion of the discussion of classification, I believe a cost causation approach is the most appropriate for BPA considering the purpose, operation, and development of the facilities comprising the FCRPS.

A final concern raised with respect to BPA's thermal classification scheme relates to the cost increases and cost overruns of the net-billed nuclear plants being constructed by the Washington Public Power Supply System (WPPSS). I fully recognize, as pointed out by the DSI's, that BPA's thermal classification scheme results in the assignment of these costs primarily to energy. I am also aware that none of these cost increases would be assigned to energy based on a fixed/variable approach to classification.

The output of the WPPSS plants is being acquired by BPA primarily to meet increasing energy requirements. I believe it is completely consistent with BPA's cost causation approach to classification to assign these costs primarily to energy.

3. Classification of Exchange Resources

Concern has been expressed that the application of BPA's thermal classification percentages to the classification of exchange resources (Table 21, COSA) fails to faithfully reflect the nature of resources involved and the load shape to which they must respond. I agree that both the load factor of the exchange load and the cost characteristics of the resources of utilities participating in the exchange program represent the relevant data on which to base a classification of the exchange resource costs. Neither of these types of data are currently available to BPA, nor will they be available until the identity of the exchange participants and the average system cost methodology is known. I have therefore concluded that BPA's thermal classification percentages represent the most reasonable basis currently available to BPA for classification of the exchange resources. The thermal classification percentages are based on the LRIC that determines the long run cost associated with satisfying capacity and energy load growth.

4. Classification of New Resources

BPA's application of its thermal classification percentages to the classification of new resources (Table 21, COSA) has been questioned on two counts. First, it was characterized as representing a departure from BPA's general cost causation approach. Second, BPA's willingness to apply a classification split to new resources without knowing their composition was criticized as being inconsistent with its decision to classify all conservation costs to energy based on a lack of knowledge regarding conservation of capacity.

I do not agree that BPA's use of its thermal classification percentages in classifying new resources is inconsistent with its cost causation approach. Rather, I consider that method to represent the best and most reasonable means of approximating a cost causation classification of the new resources, given the current lack of information regarding their exact composition. It is anticipated that initially a large portion of the resources comprising the new resource pool will be conventional thermal facilities similar to those resources for which BPA's thermal classification was developed. As the actual composition of the new resource pool becomes known, it will be appropriate in future rate filings to reflect such knowledge in the classification percentages applied to the new resources.

I do not believe BPA's approach to the classification of conservation is in conflict with its approach to classification of new resources. In each case BPA has attempted to apply the best available knowledge to these types of resources. As explained during the formal rate hearings, the conservation programs at issue are not expected to produce identifiable capacity savings.

5. Classification of Transmission Costs

Several parties have indicated a belief that some portion of transmission costs should be classified to energy. Several methods were suggested for arriving at an appropriate classification, including assigning to energy a percentage of costs equal to the BPA system load factor or assigning to capacity a percentage of costs equal to maximum line loading divided by thermal rating under contingency conditions.

I agree that some portion of BPA's transmission costs are related to energy. I also recognize that the fixed/variable approach employed by BPA classifies no transmission costs to energy. However, BPA currently is not able to theoretically support or practically apply an alternate method. None of the methods suggested to BPA appears to be fully compatible with the characteristics of BPA's transmission system. I believe that BPA should make every reasonable and timely effort to develop information that would permit an appropriate and supportable proportionate assignment of transmission costs to energy for use in future rate filings. Based on the information currently available to me, I find no precedent for employing a method other than fixed/variable for transmission classification.

D. Segmentation

In order to enhance the equity of transmission system cost allocation and to insure compliance with the requirement of the Transmission System Act to equitably allocate Federal transmission costs between Federal and non-Federal power, BPA's transmission costs were separated into seven segments (Tables 11 and 16, COSA). These segments were identified as (1) generation integration, (2) integrated network, (3) intertie, (4) fringe area, (5) preference customer delivery, (6) direct-service industrial delivery, and (7) investor-owned utility delivery. The costs assigned to the integrated network and intertie segments are allocated between both Federal and non-Federal users (Table 28, COSA). The costs assigned to the other segments are allocated, with limited exceptions, only to Federal power customers. The costs assigned to each segment are allocated to the classes of service based on the proportion of use of the facilities in each segment needed to provide each service.

Two concerns have been raised pertaining to segmentation. First, it was suggested that any lines over 69 kV that serve only a DSI load should be assigned to the DSI delivery segment rather than to the integrated network. I disagree with this position for two reasons. First, BPA has not included lines above 69 kV leading from integrated network or fringe substations to IOU or preference customer substations in the IOU delivery or preference customer delivery segments, respectively. To follow the suggested procedure only for lines serving DSI's would constitute unwarranted class discrimination.

Second, I oppose the suggestion to assign lines above 69 kV serving only a DSI to the DSI delivery segment because these lines usually have a higher capacity than the substations they serve. It is assumed that the lines will be extended to serve other substations and customers at some future time. To assign the total costs of these lines to the delivery segment of an existing customer would result in an inequitable overallocation of costs to that customer's service class.

The second concern regarding segmentation related to the general validity of BPA's segmentation method. It was suggested that studies of actual coincident power flows or coincident peak loads would better reflect actual facility use. I believe that such an approach may be a valid alternative to the approach used by BPA. I do not believe such an approach would necessarily be preferable to BPA's approach. I believe BPA's approach, based on identification of facilities with a particular use for which the facilities were constructed, is consistent with BPA's general cost causation approach to cost assignment and reflects a close approximation to actual use of facilities.

E. Allocation

BPA's procedures for allocating the costs of power generation and transmission facilities to the classes of service were of particular concern to many parties. I would like to first address those concerns relating to the composition of rate pools and the definition of Federal base system resources and the assignment of purchase power costs to rate pools. I will then turn to consideration of BPA's general approach to allocation of generation costs and, subsequently, to a discussion of the specific allocation procedures applied to exchange resources, research and development costs, conservation, deferred payment expense, fish and wildlife costs, and costs associated with the Pacific Northwest/Pacific Southwest Intertie.

1. 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.

2. Definition of the Federal Base System and Allocation of Purchase Power Costs

I support the functionalization of purchase power costs to generation and their subsequent classification and proportionate allocation to both Federal base system and NR-1 customers. This allocation procedure appropriately reflects the requirement that the Administrator acquire resources sufficient to meet all of his contractual firm obligations. The deficits for which purchases are being made include deficits which would have been present on the Federal system as well as deficits on the IOU systems that will be served at the NR-1 rate. I believe this to be consistent with the provisions of the Regional Act. It is not reasonably possible to divide the short term purchases BPA makes to cover its deficit between rate pools. The system is operated to meet one composite load at the lowest cost and we cannot identify particular purchases as going to one rate pool load or another.

Several preference customer representatives have suggested that BPA should not have allocated deficit purchase power costs to the 7(b) pool in view of the fact the Federal base system resources are more than adequate to meet 7(b) loads. I disagree with this perspective and believe that it would not appropriately reflect the purposes that the Regional Act was intended to serve. In the absence of the Regional Act, BPA would have been making these same purchases to serve its firm obligations as of the effective date of the Regional Act. These obligations would have included the loads of the preference customers and three quartiles of the DSI load. Those purchase power costs would have been allocated proportionately on the basis of load to the preference customers and the DSI's. I can find no evidence that the Regional Act was intended to remove from the preference customers the responsibility they had prior to the Regional Act for sharing a portion of the cost of meeting BPA's firm contracts, including any deficits, shared by all customers receiving firm power from BPA, nor is there any legislative history that indicates the Regional Act should create a windfall to preference customers removing such an obligation to share such costs.

It has been further suggested that BPA has circumvented the resource acquisition procedures of the Regional Act by making use of its short-term purchase authority under the Transmission System Act to meet its deficit. However, Section 6(a)(2) of the Regional Act specifically recognizes the Administrator's right to make short-term purchases under the Transmission System Act and places no restrictions on that authority. I believe the purchases are in complete accord with both the Regional Act and the Transmission System Act.

Another suggestion regarding assignment of purchase power costs was that BPA should restrict DSI second quartile loads before purchasing power to meet priority firm loads. The cost of any purchases made to serve the DSI second quartile then should be assignable to the DSI's.

I disagree with the suggested use of the second quartile restriction rights. The purpose of a reserve is to serve as a resource of last resort. The value of the reserve is the right to restrict. Once the restriction is exercised, its value as a reserve is lost and must be reestablished as quickly as possible. The reserve is intended to function not as an economical alternative to other resources, but as a final backup that can be relied on to protect the quality of firm service. Furthermore, as included in the BPA and DSI briefs, in this case, Congress intended firm service to DSI loads, subject only to restrictions upon limited conditions. To plan to forego purchases to serve the DSI second quartile would be to fail to provide firm service. In this particular rate year the DSI load will be restricted in the event we cannot acquire sufficient resources. This is consistent with shaping of FELCC to support firm loads and uniforming the risks over the critical period. Furthermore, I believe BPA has a clear obligation to acquire adequate resources to meet its firm loads which clearly includes three quartiles of the DSI load.

A final concern expressed concerning the Federal base system and the allocation of purchase power costs relates to the use of what would otherwise be secondary energy to meet a portion of the deficit assigned to the New Resource pool. Preference customer representatives have suggested this violates the preference clause by depriving them of their preference to secondary energy. They also suggest this represents a change in BPA's secondary energy policy.

As I indicated earlier in this discussion, and earlier in this document, relative to the allocation of purchase power costs, I consider BPA's deficit to include both the Federal deficit and the IOU deficit. The Administrator must seek to meet this deficit in an economically prudent manner. I consider the use of what could otherwise be nonfirm resources to serve my contractual obligations to meet a portion of this deficit, reasonable and proper and not a violation of the preference clause in light of my statutory obligation to keep BPA's rates as low as possible, consistent with sound business principles. The discussion in Section IV(H)(3) of this document further expands on this issue.

3. Allocation Factors

BPA's 1981 COSA allocated capacity related costs for both generation and transmission according to the monthly peak responsibility or 12 coincidental peak (12 CP) method (Table 19 and Exhibit 4, COSA). The 12 CP method allocates capacity related costs to each customer class in proportion to its projected monthly coincidental peak demands averaged for the 12 months in the test year. The use of coincidental rather than noncoincidental peak appropriately reflects the benefits that accrue to the system as a whole because of customer diversity. A 12 CP method was selected to reflect the relative uniformity of BPA's system monthly peak loads throughout the year.

Energy costs were allocated to customer classes in direct proportion to the energy use of each class.

The DSI's have expressed the concern that use of a 12 CP allocation method for capacity related costs is inconsistent with BPA's Time-Differentiated Pricing Analysis and results in an excessive allocation of these costs to high load factor customers. I believe the DSI's concerns in this area are unjustified. The Time-Differentiated Pricing Analysis indicated that there should be no seasonal differentiation of transmission costs. Although winter peak loads may be somewhat higher than summer peak loads, the capacity of transmission facilities is reduced during the summer season by higher ambient temperatures. The 12 CP method clearly is consistent with the lack of a seasonal differential in transmission capacity costs.

The Time-Differentiated Pricing Analysis also indicates there should be a seasonal differentiation of generation capacity costs. In the Summary Rate Design Study the seasonal load amounts are used to allocate the generation capacity costs among classes of service. This rate design step effectively replaces the use of the 12 CP allocation method in the COSA for generation capacity costs.

It was further suggested that BPA's choice of a 12 CP method was in conflict with the general guidelines applied by the FERC in determining the appropriateness of using a 12 CP method. I believe that the fact that BPA is coupling the use of the 12 CP method with a seasonal differentiation of its rates negates this concern.

A final concern expressed over the 12 CP method related to the use of maximum noncoincidental demand in some cases and average demand in others to develop noncoincidental demands. It was suggested that such a procedure might produce a biased allocation. Since BPA's coincidence factors are based on average demand, I do not believe that use of average demand in those cases where BPA has no forecast available for maximum noncoincidental demand would produce a biased allocation of capacity costs.

4. <u>Allocation of Exchange Resource Costs</u>

In the initial 1981 rate proposal, BPA assumed a 100 percent load factor in developing an allocation of exchange resource costs. A number of parties expressed concern over the appropriateness of this assumption. I recognize that the load factor of the exchange load will be significantly below 100 percent and that use of an assumed load factor of 100 percent would result in an underallocation of capacity costs to those loads.

Rather than assuming a 100-percent load factor for the exchange load, the allocation of exchange costs in the final proposal is based on the ratio of the 12 CP of the preference customers to their energy requirement. The energy requirement of the exchange load is then multiplied by this ratio to arrive at a 12 CP estimate for the exchange costs. In essence, therefore, the resulting allocation is a reflection of the load factor of the preference customers. I believe this procedure is the best and most reasonable method currently available to BPA for allocating the exchange costs.

One party suggested that separate capacity rates for preference and exchange customers as an appropriate means of recognizing differences between the preference customer and exchange load factors. I believe such a differentiation of capacity charges is without basis. There is no difference in the cost of providing capacity to preference customers versus exchange customers. The fact that BPA's proposed rates contain separate charges for capacity and energy insures that customer load factors will be reflected appropriately in the charges billed to each customer.

The DSI's have suggested that, by allocating transmission costs in part to the fringe area segment and as a component of the average system cost of exchange resources, BPA has in effect double billed them for transmission costs. For purposes of rate development, I consider it appropriate to treat the IOU exchange as a purchase and sale of resource. The DSI's have been allocated that portion of the IOU average system cost intended to cover the transmission of exchange power from the IOU resources to points of interconnection on the BPA system. I also consider the inclusion of a transmission component with respect to BPA's network and fringe costs to be appropriate. The BPA transmission component is representive of the costs of transmitting exchange power from the points of interconnection between BPA's system and the systems of the IOU's to the DSI loads. Both the loads of the DSI's and the loads of the exchange customers are met by BPA through power sales. It is appropriate to allocate transmission system costs among all sales and services offered by BPA. I disagree with the claim that this constitutes double billing of the DSI's.

Some parties have suggested that the costs of the exchange should be treated as an accounting transaction rather than a resource transaction. The DSI's have further suggested excluding the treatment of these costs from the COSA. They indicate this would avoid the unnecessary introduction of errors relating to the load factor and average system cost assumptions into the analysis.

I believe that the Regional Act requires BPA to treat the exchange resources as a resource acquisition and grants the Administrator the authority to make the appropriate allocation. The inclusion of the exchange resources in the COSA is necessary in order to arrive at an appropriate allocation of the cost of the Federal transmission system as well as the exchange resource costs.

5. Allocation of Research and Development Costs

In BPA's initial proposal most research and development expenses were functionalized to transmission and assigned in total to the integrated network segment. It was suggested during the course of BPA's formal rate hearings that a portion of this expense might appropriately be assigned to the generation-integration segment. I agree that not all of BPA's research and development expense should be assigned to the integrated network segment and that a portion should be assigned to generation. In the final proposal 62 percent of research and development costs have been functionalized to generation whereas the remaining portion has been functionalized to transmission.

6. Allocation of Conservation Costs

In BPA's initial proposal the total projected costs of both the conservation and billing credit programs were allocated to the New Resource pool. The load reductions associated with these programs were assigned to the New Resource pool for the purpose of calculating the proportion of purchase power expense to be assigned to the New Resource pool; however, no reduction was made in BPA's total purchase power requirements. These assignments were based on the assumption that those customers that bear the cost of conservation programs should be in receipt of the resulting load reductions.

In the final proposal there has been no allocation of costs or load reductions associated with billing credits. This modification was made in view of uncertainties concerning the amount of billing credits likely to be granted during the rate year and the specific potential load reductions that might be associated with these expenditures.

Several concerns were raised regarding the appropriate method for allocating both the costs and projected load reductions associated with conservation programs. One suggestion was that it would be best to use a uniform allocation of conservation costs across all energy use, given the lack of information currently available concerning the future distribution of conservation benefits. I would agree that this would be a reasonable procedure if it were not for the fact that the load reduction associated with conservation has not been assigned in a correspondingly uniform manner.

A number of parties have suggested that both the costs and the load reductions associated with conservation should be assigned to those customers whose loads are being reduced. I believe this alternative is consistent with BPA's treatment of conservation in the final proposal (Table 26, COSA). The load reductions and costs associated with conservation by preference customers have been assigned to the Federal base system pool. The load reductions and costs associated with conservation on IOU systems have been assigned to the New Resource pool. I believe this is an appropriate distribution of both load reductions and costs associated with conservation.

7. <u>Allocation of the Cost of Deferred Payments</u>

Deferred interest through 1981 is included in BPA's Repayment Study as being repaid in fiscal year 1982. These costs have been assigned to the regional cost pool and will be recovered under the priority firm rate.

A representative of the Washington Utilities and Transportation Commission has indicated that deferred interest and amortization should not be assigned in any way to residential/rural exchange customers who were not served by BPA at the time of the interest deferrals. Preference customer representatives, on the other hand, point out the appropriateness of such an assignment based on the fact that a principal cause of the prior year deficit is associated with increases in the cost of the net-billed nuclear facilities being constructed by the Washington Public Power Supply System. These facilities will ultimately serve all of BPA's customers.

I consider the cost of deferred interest to be a Federal base system cost that is appropriate for assignment to any and all customers served by Federal base system resources, including the residential and rural customers of utilities participating in the resource exchange program. In the ratemaking process it is typical to have deficits and surpluses, since rates are based on future test year projections that invariably are different than actual conditions during the period the rates are in effect. This is because of varying weather conditions, deviations from load forecasts, and variations in available energy from a hydro system. Typical utility practice is to forecast revenues for average conditions and not to determine which customers were taking service in the particular period that the deferred costs or rate reductions occurred. Historically, BPA has not attributed revenue deficiencies or surpluses to specific rate classes and attempted to rebate or recover those deficiencies from that rate class in the future.

8. <u>Allocation of Fish and Wildlife Expenses</u>

In BPA's initial proposal, the cost of facilities associated with the mitigation of impacts to fish and wildlife by hydroelectric plants were assigned to all power users. Assignment was based on the assumption that these mitigation efforts would benefit all citizens of the region, rather than just those served by Federal base system resources.

In the course of BPA's formal rate hearings it was suggested by a representative of the InterCompany Pool that the need for mitigation facilities at hydroelectric plants was directly related to the plants themselves and should be included as a cost of the plants and be recovered from customers supplied by the plants. The Regional Act provides for the collection of costs for fish and wildlife mitigation through power rates. The Regional Act does not indicate that this cost should be collected only from customers served by hydroelectric facilities. It is anticipated that at least a portion of the expense associated with fish and wildlife may be directed toward programs which are unrelated to the effects of hydro plants. As the programs for which these expenses are incurred become better defined, it may be possible to develop a more disaggregated allocation of these costs for future rate filings.

9. <u>Allocation of Intertie Costs</u>

The costs of the Pacific Northwest/Pacific Southwest Intertie have been allocated to nonfirm energy service and various intertie transmission services. That portion of the transmission system cost assigned to the intertie segment has been allocated to seasonal capacity, formula power transmission, Columbia Power Storage Exchange (CSPE), capacity/energy exchange, and nonfirm energy (Table 12, COSA). The allocation of intertie costs to nonfirm energy is consistent with the fact that an original purpose for the investment in the intertie was the transmission of nonfirm energy.

A representative for Pacific Gas and Electric has suggested that BPA's allocation of transmission capacity costs to nonfirm energy is inappropriate in view of the fact that nonfirm energy purchasers enjoy no capacity rights. Additional concerns voiced by Southwest representatives relate to the consideration given to intertie functions other than transmission of nonfirm energy in allocating intertie costs. One party suggested the granting of a credit against intertie costs for exchange revenues.

I believe the allocation of a portion of the intertie costs to nonfirm energy appropriately reflects the purposes underlying the investment in the interie. This allocation is not intended to reflect any entitlement by nonfirm energy purchases to transmission capacity rights. As I previously indicated, the intertie costs not allocated to nonfirm energy were allocated in the COSA to seasonal capacity, formula power transmission, CSPE, and capacity/energy exchange. I believe this allocation appropriately reflects the services provided by the intertie. Since this allocation has been made in the COSA, there is no basis for applying an additional credit for benefits resulting from exchange transactions.

F. Results

Of the total revenue requirement of $1,125,893,000 (exclusive of exchange costs), $871,243,000 was functionalized to generation and $254,650,000 was functionalized to transmission. Of the amount functionalized to generation, $308,852,000 was classified to generation capacity and $562,391,000 was classifed to energy production. Of the costs classified to generation capacity, $291,812,000 represented expenses of the FCRPS and $17,040,000 were annual costs associated with the Regional Act. The energy production costs of the FCRPS were $395,442,000. The portion of Regional Act annual costs classified to energy production was $166,949,000. The Regional Act annual costs contain no costs functionalized to transmission. All transmission costs are associated with the FCRPS (Table 3, COSA).

The amount of exchange resource costs which are Regional Act annual costs is currently unknown. However, 90 percent of these costs was functionalized to generation and 10 percent was functionalized to transmission. Of the exchange costs functionalized to generation, 13 percent was classified to capacity and 87 percent was classified to energy (Table 3, COSA).

Based on these results, Federal base system resources were allocated a total cost of $931,129,000. The exchange resource pool was allocated a total cost of $26,897,000 plus the cost of exchange resources. The total cost assigned to the new resources pool was $167,867,000 (Table 3A, COSA).

VII. Time-Differentiated Pricing Analysis

A. Introduction

As a part of the rate process, a time-differentiation analysis of average (embedded) and long run incremental costs was prepared. Embedded unit costs of energy and both embedded and long run incremental unit costs of generation capacity and transmission are considered to vary over different time periods. Incremental energy costs are considered to be independent of hourly or seasonal considerations.

Time-differentiated pricing is a rate design concept that has evolved because demand for electricity varies over the day and year. To the extent peaks in demand or the sustainment of peaks cause higher unit costs, time-differentiation deals with this within the framework of a pricing structure. Time-differentiated pricing, which strengthens the relationship between costs and prices, is based on the concept of cost causation.

The Time-Differentiated Pricing Analysis (TDPA) time-differentiates incremental generation capacity costs derived from BPA's LRIC. These costs are incurred because of increases in peak period because demand and are assigned in total to the peak period. No attempt was made to discriminate within the peak period; every hour is considered uniformly responsible for BPA's capacity expansion costs.

The embedded costs for generation capacity, energy, and transmission for test year FY 1982 are from the Cost-of-Service Analysis (COSA). The general method used for time-differentiating BPA's embedded capacity costs is founded on a procedure developed by EBASCO Services, Inc., for the Electric Power Research Institute's Rate Design Study.

BPA employed a method for measuring an energy cost differential that is different from that used for capacity. Reservoir storage costs formed the basis for the seasonal energy differential. Transmission costs, both incremental and average, are diurnally but not seasonally time-differentiated.

B. Costing/Pricing Periods

From an analysis of BPA's firm load for FY 1975-1979 (Table 3, TDPA), FCRPS generation data, West Group Region probabilities of negative margin (PONM)(Table 1, TDPA), and ambient temperatures at time of transmission peaks (Charts 2 and 3, TDPA), I determined that the peak period for generation capacity should be defined as December through May, Monday through Friday, 7 a.m. to 10 p.m. (Table 4, TDPA). A secondary peak season applicable only to embedded generation capacity costs should be June through November, Monday through Friday, 7 a.m. to 10 p.m. (Table 6, TDPA). The combination of these two periods (all months, Monday through Friday, 7 a.m. to 10 p.m.) forms the peak period for incremental and embedded transmission costs. The offpeak capacity hours should be all other hours of the year.

Embedded energy costs vary seasonally, corresponding to seasonal changes in production from hydro storage (Table 7, TDPA). The peak period is September through March and the offpeak period is April through August.

Three distinct comments were received regarding these time periods: (1) generation capacity time periods should be based on a measure that is independent of scheduled maintenance and discernable for the FCRPS such as monthly Federal peak loads resulting in a peak season for the FCRPS of October through March; (2) although the energy time period is not necessarily incorrect, it should be based on the seasonally periodic production from Federally acquired thermal units as well as production from hydro storage; and (3) storage costs are not a basis for an energy differential because storage facilities provide energy the year around.

The peak generation capacity seasonal period is delineated on the basis of 10 years of projected monthly West Group Region PONM's, under average water conditions (Tables 1 and 2, TDPA). I agree that PONM's, because they focus on loads in relation to capability, are to some extent a function of scheduled maintenance and that because of revisions in schedules, particular months may, in retrospect, have been misclassified. However, it is projected for the West Group Region for the next 10 years that PONM's will be distributed primarily within the December through May period. It would have been preferable to determine this seasonal time period on the basis of monthly Federal PONM's, but this information is unavailable. It is preferable to use West Group PONM's rather than Federal loads alone. This is because the former includes these loads and, more importantly, because capacity costs for the FCRPS vary not in the sense that explicit costs per kilowatt are necessarily higher at time of peak but rather that additional load warrants increments to capacity in some time periods but not in others. Therefore, the capability of the resources must be considered.

Regarding the correct basis for an energy differential, I am not convinced of the seasonality of prodution from baseload thermal plants. These resources have been added to the FCRPS to supply needed energy on an annual basis according to BPA's planning criteria which assumes critical water conditions. From a planning perspective, increases in demand for energy at any hour of the year require baseload thermal additions. These plants are designed to be operated throughout the year except for planned maintenance, refueling outages, and forced outages. These outages are dependent upon many factors including fuel life, equipment failure, demand for energy, and the availability of alternative resources, and may occur throughout the year. Thus, the costs of providing energy from baseload thermal plants are the same for each hour of the year, regardless of operating characteristics.

Power related hydro storage costs, on the other hand, do seem to be a bona fide basis for an energy differential because in order to enhance the overall firm energy load carrying capability of the FCRPS, production from storage is necessarily seasonal. During the summer months of April through August there is little production from storage; that is, the reservoirs are filling. During September through March, the majority of power production from storage occurs. Data from BPA's "Power System Statement," indicated that from 1975 to 1979, 92 percent of the energy from storage was produced during the September through March period (Table 7, TDPA).

C. Assignment of Costs

Incremental capacity costs are assigned to time periods based on the distribution of relative PONM. Since all PONM's are confined to the peak period, 100 percent of the incremental generation capacity costs are assigned to the December through May, Monday through Friday, 7 a.m. to 10 a.m. period (Table 5, TDPA). One hundred percent of the incremental transmission capacity costs are assigned to the diurnal peak period without a seasonal distinction (Table 5, TDPA).

Embedded generation capacity costs for FY 1982 are assigned to the peak, secondary peak, and offpeak periods based on the duration of BPA's hourly firm load averaged for 5 years (Charts 4 and 5, TDPA). The costs are assigned as follows: 38.5 percent to peak, 21.3 percent to secondary peak, and 40.2 percent offpeak (Table 9, TDPA). These percentages differ from those initially proposed due in part to an arithimetic error in line (6), Table 9, of the February 1981 TDPA.

Embedded energy costs are apportioned as follows: 63.1 percent to the September through March period and 36.9 percent to the April through August season (Table 10, TDPA).

A comment was received on the assignment of embedded transmission costs to the peak and offpeak periods. As initially proposed, this division was based entirely on the allocation of generation capacity costs between peak and offpeak periods, without regard to monthly seasons. BPA believes that the diurnal division of generation capacity costs was a suitable proxy for the division of transmission embedded costs because of the relationship between generation capacity and the transmission system. However, the resources are clearly distinct commodities. A question arose as to whether there is evidence to support the hypothesis that the diurnal variation in transmission system costs is the same as in generation capacity costs.

BPA does not distinguish between peak and baseload transmission costs and, consequently, the method used to apportion generation capacity may not be duplicated to apportion transmission costs. I recognize that there is not necessarily a fixed proportional relationship between the costs for peak generation and peak transmission. Therefore, Table 11, TDPA, which differentiates transmission costs, was changed to reflect the differing proportions of the annual and investment costs of the two resources. Determination of the percentages of annual and investment transmission costs that are related to peak is still based on the exogenous information for generation capacity. However, by recognizing the differing cost structures, the percentage of transmission costs assigned to the peak period was decreased from 59.8 percent to 59.0 percent.

The TDPA culminates with the assigning of Federal base system costs by classes of service to the embedded cost time periods (Tables 12 and 13, TDPA).

VIII. Transmission Rate Design Study

A. Introduction

The Transmission Rate Design Study (TRDS) formulates a system of transmission rate schedules that recovers the revenue requirement derived from the allocated costs for firm transmission service in the COSA and provides rates for nonfirm and specific facility uses. A variety of factors are important in the design of BPA's transmission rate schedules. Primary among these factors are BPA's legislative requirement to equitably allocate the recovery of costs of the transmission system between Federal and non-Federal power utilizing the system and maintaining consistency with the provisions of current wheeling contracts. Additional factors that are considered in the design of the transmission rate schedules are: competition from non-Federal transmission facilities, treatment of non-Federal costs and uses, cost studies (LRIC Analysis and TDPA in addition to the COSA), equitable sharing of the benefits and risks of the FCRTS, efficient resource utilization, rate integrity, rate continuity, and ease of administration of the rate schedules.

In evaluating BPA's present transmission rate structure in view of the above factors, I find that while the current rates serve the purpose of rate continuity and integrity and are consistent with BPA's contractual obligations, they are contrary to many of the other rate objectives. BPA has received many comments from customers on the inadequacy of current transmission rates. In addition, FERC remanded the current rates to BPA for further explanation and documentation. In an attempt to address the many concerns and more closely address the rate design objectives adopted by BPA, several alternative approaches to a postage stamp rate were examined. A uniform, postage stamp rate schedule with a broader, more flexible service could meet BPA's statutory requirements, answer many of the customer's concerns and better serve the other rate objectives. A uniform transmission rate schedule would reflect the cost causation factors identified in BPA's cost studies; reduce administrative complications; assure a more equitable sharing of the risks and benefits of the integated system; improve the efficiency of resources use; and equitably treat Federal and non-Federal costs, uses, and facilities.

Therefore, for these reasons I have developed two sets of transmission rate schedules. Set A schedules update BPA's current transmission rates and as such reflect historic decisions embodied in the present contractual arrangements. Set B, the IR-1 schedule, reflects many of the other factors, provides customers with a broader, more flexible service at a uniform rate and attempts to respond to the needs of BPA's customers. In February 1981, BPA published a notice of intent to develop a new transmission policy to reflect the additional factors and to respond to BPA customers' changing needs. The IR-1 schedule is designed as an interim, 1-year set of rates and contracts to offer more flexible sevice while the new transmission policy is being developed.

The Set A schedules consist of three rate schedules: Formula Power Transmission (FPT-2) for wheeling of firm power, Energy Transmission (ET-2) for wheeling of nonfirm power, and Use-of-Facilities Transmission (UFT-2) for wheeling of firm power over specific and limited facilities. Set B, the Integration of Resources (IR-1) schedule, is for the integration of resources into the network and for firm intertie service. The initial proposal included rate schedule IS-1 for Set B intertie service. This rate is now included in the IR-1 schedule. Rate schedules ET-2 and UFT-2, but not FPT-2, are available for use by customers using IR-1 for firm Network and Intertie service.

B. Determination of Firm Wheeling Revenue Requirement

1. Crediting of Nonfirm Revenues

The revenue requirement for the wheeling of firm power (rate schedules FPT-2 or IR-1) is derived from the costs allocated to FPT in the COSA. Before designing the rate schedules, the revenue requirement is adjusted to reflect revenues from the sales of nonfirm energy (NF-1) and nonfirm transmission (ET-2). Excess revenues from the transmission component of nonfirm energy sales and all revenues from nonfirm transmission service are credited to all firm transmission rate classes in proportion to the costs allocated to those rate classes in the COSA. No comments were received on this methodology. Therefore, I am using the same four-step process of cost adjustment as was used in developing the initial proposal.

The first step involves separating the total, or unadjusted, FPT revenue requirement from the COSA into its Integrated Network and Intertie components (Table 1, TRDS).

The second step credits revenues from transmission-related nonfirm energy sales (NF-1) to the unadjusted revenue requirement. This distributes the benefits of the excess revenues from the transmission component of the NF-1 rate to all transmission system users. The transmission-related nonfirm energy sales revenue is the product of the estimated NF-1 sales and the NF-1 transmission cost component. Transmission-related NF-1 revenue is reduced by intertie costs allocated to nonfirm energy in the COSA to obtain total transmission-related excess revenues (Table 2, TRDS). These excess revenues are then segmented into Integrated Network and Intertie components according to the segmentation of total transmission costs in the COSA (Table 3, TRDS).

The third step involves determination of the ET-2 rate and annual revenues from the ET-2 rate (Table 4, TRDS). The ET-2 rate is set at the average cost of firm transmission, adjusted for nonfirm energy sales. The costs per 12 CP (megawatts) over the Integrated Network and the Intertie are transformed into a mills per kilowatthour rate using the projected FY 1982 ET load factor. Projected revenues are calculated by applying the rate to projected sales. ET-2 revenues are then segmented in the same manner as NF-1 revenues.

The fourth and final step is to allocate the NF-1 and ET-2 excess revenues to FPT and adjust the IR-1 and FPT-2 revenue requirements accordingly (Table 5, TRDS). The unadjusted revenue requirement for firm wheeling over the Integrated Network less its FPT allocated offset is the adjusted revenue requirement for firm service over the Integrated Network, or the IR-1 network revenue requirement. The unadjusted revenue requirement for firm wheeling over the Intertie less its allocated offset is the adjusted revenue requirement for firm service over the Intertie, or the IR-1 intertie revenue requirement.

The sum of these revenue requirements for the Integrated Network and Intertie equals the FPT-2 revenue requirement. Thus, rate schedule FPT-2 is designed to collect the same total revenues as rate schedule IR-1.

2. Adjustments to Recover the Projected Revenue Shortfall

The choice that I am offering between the Set A or Set B rates causes BPA to anticipate a small shortfall from the COSA determined revenue requirement to be recovered from FPT service. This shortfall is the result of customers choosing the option that will require less revenue to be paid to BPA for transmission services. To recover this anticipated shortfall in revenues it was necessary to adjust both Set A and Set B rate schedules.

This adjustment of rate schedules necessarily began with a projection of the amount of the shortfall. To estimate the shortfall, I determined which BPA transmission customers are likely to switch from their current FPT rates (Set A) and contracts to the alternative IR-1 rate (Set B). At this time I anticipate that only three customers will choose the Set B rate: Seattle City Light, the City of McMinnville, and Cowlitz County PUD.

A purpose of the interim contract negotiation meetings was to give BPA an idea of which customers are likely to choose the Set B rate schedule. In response to BPA's presentation at the May 18, 1981, meeting, the three utilities named above expressed interest in changing to the IR-1 rate. Additionally, BPA determined that it would be economically advantageous for those utilities to receive service under the IR-1 rate. On this basis, I have assumed that these utilities will choose the IR-1 rate and that a revenue shortfall will result because these utilities will pay less under the IR-1 rate than they would have under the FPT-2 rate.

The adjustment necessary to recover this shortfall in revenues was a two-cycle process. In the first cycle, the FPT requirement derived in the COSA was adjusted for nonfirm revenues as described in Section VIII(B)(1)), and this adjusted revenue requirement from FPT rates was $29.3 million (Table 5, TRDS). Rates were then calculated for both FPT-2 and IR-1 with each rate designed to recover the entire $29.3 million. Unadjusted FPT-2 and IR-1 rates are shown in Tables 7 and 8 TRDS, respectively.

The amount of projected revenue that would be recovered from the unadjusted rates was based on the assumption that Seattle City Light, City of McMinnville, and Cowlitz County PUD will choose the IR-1 rate schedule (Table 9, TRDS). The sum of these revenues subtracted from the revenue requirement ($29.3 million) was the projected shortfall, which is 6.3 percent of the projected unadjusted revenue recovery. Thus, to recover this shortfall the revenue requirement used to derive the FPT-2 and IR-1 rates was increased by 6.3 percent, to $31.2 million (Table 5, TRDS).

In the second cycle, FPT-2 and IR-1 rates were separately determined (Table 7 and 8, TRDS, respectively) in order to recover the assumed revenue requirement of $31.2 million. Projected revenue recoveries from these adjusted FPT-2 and IR-1 rates were determined. The adjusted FPT-2 revenue recovery was determined excluding Seattle City Light, the City of McMinnville, and Cowlitz County PUD, and the adjusted IR-1 revenue recovery was determined for the three utilities. The sum of these two adjusted revenue recoveries totals $29.3 million, the FPT revenue requirement (Table 15, TRDS).

C. Rate Development

1. Formula Power Transmission Schedule, FPT-2

a. Derivation

Schedule FPT-2 represents a revision of the transmission components of the BPA "wheeling formula" that was developed in the 1950's and has been incorporated in some of BPA's wheeling contracts since that time. The FPT-2 rate schedule includes unit costs of various components of the FCRTS. Some comments have indicated that the separate identification of specific services under the FPT-2 is unjustifiable given the postage stamp service that firm power customers receive. Such services as distance, identification of network facilities, and one-way wheeling between specific points of interconnection are variously objected to. The IR-1 rate is an attempt to avoid such practices and to eliminate the need to identify specifically such other charges as station service to a customer's off-line generator. While I feel that the costs of the portions of the Integrated Network should not be subdivided or allocated according to distance and types of facilities, some FPT contracts appear to require continuation of this historical rate design, and the process I have used to design the FPT-2 rate conforms to the contract constraints. I notice that the same party which advocates overturning FPT contractual provisions relating to point-to-point service, billing determinants, and losses in the rate process, objects to BPA's proposed treatment of parallel path scheduling for the IR-1 rates because such treatment is inconsistent with current contracts.

Nearly all FPT wheeling is designated as using the Integrated Network and Intertie segments of the FCRTS. The projected costs and power flows associated with these segments are used to derive the wheeling formula. The first step in this process is a subsegmentation of facilities. The components of the Integrated Network are grouped into two major subdivisions, the main grid (230 kV and higher) and the secondary system (primarily 115 kV). These main grid and secondary systems are then further subdivided by voltage, nature, and purpose of the facility (Figure 1, TRDS). The Intertie segment is the Pacific Northwest-Southwest Intertie, AC and DC portions.

The power flow through the various facilities is determined from a simulated power flow study. The power flow used for this rate proposal, case number J8240FY82 completed in the Spring of 1981, is a simulation of January 1982 peak load conditions. This is the time of the year when the FCRTS peak normally occurs. However, some areas of the FCRTS experience peak loading in the summer; therefore to account for this phenomenon, an August adjustment was made to the total use.

The source for loads and resources for this study is the "Long Range Projection of Power Loads and Resources for Resource Planning" (1980 Blue Book forecast). Firm loads, firm interchange schedules, and industrial nonfirm loads were included in the power flow study. All baseload thermal generation was operating as needed with hydro generation run for median water conditions and the transmission system was operated as planned with all lines in service. The results of the power flow study are summarized in Figure 1, TRDS.

The annual costs for each component of the transmission system are developed by adding operation and maintenance expenses to the interest and amortization expenses. The interest and amortization expenses are calculated using the average life of each type of facility and the average interest rate (Table 6, TRDS). The calculation of the FPT-2 rate is accomplished by summing the annual costs and the power flows for each type of facility according to the rate components (Table 7 and Figure 2, TRDS) and then constraining the annual costs to the FPT revenue requirement (Table 7, TRDS). The rate for each component is derived by dividing the constrained annual cost by the megawatts and megawatt-miles obtained from the power flow.

The unit costs must be constrained to the COSA determined revenue requirement because the FPT development process uses a very different method for determining and allocating annual costs than does the COSA. The annual costs in the COSA are the sum of operating expenses, depreciation expense, and the investment base (net plant in service) times the weighted average interest rate. The annual cost of a facility in the FPT process is the operating expense plus the equalized annual payment needed to amortize the facility over its useful life and pay interest on the unamortized portion. Revenues from NF-1 and ET-2 sales were not credited against the annual costs used to derive the unadjusted FPT rate.

The COSA used the 12 CP method to allocate costs between Federal and non-Federal power. The FPT process used a unit cost per megawatt or megawatt-mile method for cost allocation. Also, the megawatts and megawatt-miles used in the power flow do not correspond precisely to the contract demands and contract miles that are used as billing factors.

It would, perhaps, be possible to quantify these discrepancies and make separate adjustments to the component annual costs or billing determinants. Adjustments of this nature were made in the 1976 filing for ET-1 revenues and for the policy of amortizing the high interest rate investment first. This type of analysis was not necessary for this rate filing because the FPT process is being used to design rates rather than determine the overall revenue level. The overall revenue level is derived in the COSA but is adjusted for opportunity sales. The relative levels of the rate components for FPT-2 are derived from subsegmentation of annual costs and power flow data.

A number of parties commented that the FPT rate factors for individual contracts shown in the TRDS for the initial proposal were neither up to date nor did they reflect special considerations in the contracts. These comments generally were correct and the final rate was developed using corrected rate factors (Tables 10 and 11, TRDS).

Since the Washington Water Power-San Diego Gas & Electric contract (No. 79101) has provisions that limit the frequency of rate adjustments to no more than once every five years, no increase in revenues from this contract can be achieved until June, 1982. Consequently, the adjustment factor in Table 7, TRDS is slightly higher in order to allow for this contract constraint.

b. Description

The main grid rate components of the FPT-2 schedule include: a Main Grid Distance Factor, a Main Grid Integration Terminal Factor, a Main Grid Miscellaneous Facilities Factor, a Main Grid Terminal Factor, and a Main Grid Delivery Terminal Factor. This schedule's secondary rate components are: Secondary Transformation Factor, a Secondary System Integration Terminal Factor, a Secondary System Distance Factor, a Secondary System Intermediate Terminal Factor, and a Secondary System Delivery Terminal Factor.

The main grid distance factor is based on distance in air miles between points of integration and delivery, multiplied by 1.15. Other main grid components are based on use of main grid terminals and facilities. The secondary system distance factor is based on distance in circuit miles of secondary system transmission lines between the main grid and the point of delivery. Other secondary system components are based on use of secondary system terminals and transformation facilities. The Intertie FPT-2 rate component is based on use of the intertie transformation and transmission facilities. The billing determinants for the FPT-2 rate are contract demand and contract demand times mileage.

Some customers have objected to the use of contract demand as being a ratchet and therefore inappropriate in combination with the 12 CP method. While recent FERC rulings have generally been consistent with this view, not all ratchets have been eliminated (Florida Power and Light Co., Opinion No. 784 E-8008, 1976), and the rulings have not applied specifically to transmission rates. Because virtually all of the costs of a transmission system are fixed costs, contract demand billing determinants are often used for long term wheeling arrangements. Furthermore, rather than discouraging transactions as some customers have maintained, use of the contract demand actually encourages them up to the level of the contract demand.

Several changes have been made to the FPT-2 schedule in addition to increasing the level of charges. The FPT-2 schedule is available for transmission of firm power over the Integrated Network and Intertie segments, for both full-year and partial-year service. The FPT-1 schedule was available for transmission of firm power for a full year only. This change is part of an effort to make the availability of schedules FPT-2, ET-2, and UFT-2 mutually exclusive.

Charges have been developed for two types of partial-year service. Unplanned transmission service for firm power will be provided for a 1-month charge per year as long as usage in the year does not exceed 730 hours. Service for agreements where the term is less than 5 years and which specify service for fewer than 12 months per year will be charged the usual rate during months for which service is specified and 20 percent of the usual charge during other months. Service is limited to 5-year terms because this is the usual planning period for transmission system additions. BPA's intention is to not build additional facilities to provide this type of service. The 20 percent charge during months of nonuse is reasonable because the level of the FPT-2 rate was developed based on a yearly contract demand. Analysis of 1979 data indicates that had the rate been based on unratcheted demands, the charges would have to be 20 percent higher in order to recover the same amount of revenue.

Concurrent with this rate filing, BPA will eliminate the Z-factor credit. The Z-factor credit is a reduction in the billing determinant (contract megawatts) for those FPT customers who are also Federal power customers. The credit is included in the contracts rather than in the rate schedule. The level of credit is determined by the difference between the wheeling customer's load factor and BPA's load factor. The Z-factor was originally included in contracts to recognize the diversity between a customer's transmission demands and Federal power demands. Concurrent with the 1976 Transmission Rate Filing, BPA indicated that the Z-factor would be phased out; with a 50-percent reduction at that time, to be followed by a complete elimination in the next transmission rate filing. In allocating transmission costs between Federal and non-Federal customers, full recognition is given to economies resulting from diversity of demand on the transmission system. Therefore, no further recognition is needed and continuation of the Z-factor would result in those customers receiving double credit for diversity.

2. Energy Transmission Schedule, ET-2

a. Derivation

This class of service is not allocated costs in the COSA. Therefore, it is necessary to determine the level of the rate by other means. The technique used to develop the ET-2 rate is to calculate the unit cost per monthly coincidental peak kilowatt for the Network and Intertie segments by dividing the total COSA derived costs for these segments that are adjusted for nonfirm energy revenues, by the estimated monthly coincidental peak kilowatts. The ET-2 rate is calculated by applying the estimated ET load factor to the unit cost per kilowatt of the ET class (Table 4, TRDS).

b. Description

This schedule is for transmission of non-Federal nonfirm electric energy using excess capacity of the FCRTS. This rate is not available for the transmission of energy that is used to meet firm obligations on a planning basis nor for energy that cannot be interrupted. The availability of this ET-2 rate has been changed from that in the ET-1 schedule, which was available for incidental transmission using excess capacity. This change is part of an effort to make the availability of the FPT-2, ET-2, and UFT-2 schedules mutually exclusive. It has been asserted that the availability of the ET-2 rate should not be strictly limited and that general availability of this schedule promotes the efficient use of generation. I agree that efficient use of resources is an important consideration. Accordingly, the availability of the ET-2 rate for economy energy transactions is limited only by the capacity of the transmission system. I do not agree, however, that the ET-2 rate should be available for transmission of resources that a utility plans to use to serve its firm loads. Therefore, if a utility shows a resource to be meeting firm load on a planning basis in its Pacific Northwest Utilities Conference Committee (PNUCC) projections or for determining its computed demand, I will continue to insist that it have a firm transmission path.

The ET-2 rate includes component costs for both the FCRTS transmission system and the PNW/PSW Intertie. The previous rate, ET-1, had different charges for the main grid and secondary systems as well as a separate charge for delivery of replacement energy. In the ET-2 schedule these charges have been combined into a single rate for Integrated Network delivery. A charge for Intertie use only has been added and will be used in conjunction with the IR-1 schedule. In addition, the provision for losses in ET-1 has been eliminated in ET-2 and is to be treated as a contract matter.

Concerns have been raised because the combination Network/Intertie charge was increased more than the Network-only charge. In the ET-1 rate, transmission distance was assumed to be a major cost factor, and Intertie wheeling was assumed to be a short Network distance from the mid-Columbia plants. However, for reasons discussed in conjunction with the

IR-1 rate, I do not believe that distance is an identifiable cost factor to consider in the development of Network transmission rates. Therefore, the ET-2 rate has been developed on an average cost basis without regard to distance.

Parties raised questions about how the ET-2 rate would be used in conjunction with the FPT-2 rate and the IR-1 rate. Customers on the FPT-2 schedule would use the ET-2 schedule for all secondary transactions. Customers on the IR-1 rate could wheel secondary under IR-1 to any IR point of delivery including to the Pacific Northwest-Pacific Southwest Intertie. The ET-2 rate would be used to deliver power to non-IR points of delivery, for delivery over the Intertie, and to wheel secondary power from resources not integrated by the IR-1 schedule.

3. Use-of-Facilities Transmission Schedule, UFT-2

This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. UFT is no longer available for new agreements for service over the Integrated Network segment or the PNW/PSW Intertie. A number of current UFT agreements involve Network facilities, and some BPA customers have argued that the UFT-2 rate should be available for new agreements of this nature. The customers have noted that this availability would be especially important in instances where the IR-1 or FPT-2 rate may not be competitive with a utility's alternative costs.

I do not agree, however, that UFT is appropriate for Integrated Network service. Customers connected to the Integrated Network automatically receive services such as stability, reliability of transmission, backup power sources, and a system for marketing surplus power. Because of the integrated nature of the FCRTS Network it is very difficult to identify use of a specific Network facility and assess the cost or value of its specific use. Power may take any of several paths to get from one point on the Network to another. However, in the case of power transmitted solely on the fringe facilities, specific facility use is easier to identify; consequently, BPA has developed the UFT-2 schedule based on wheeling customers' specific uses of types of non-network facilities.

This schedule contains a cost formula rather than a specific rate. The UFT-2 schedule is a continuation of the previous schedule, UFT-1, in terms of its applicability to identifiable facilities. The UFT-2 rate is designed to recover the specific investment costs of the particular facility. One change BPA has made in the cost formula involves calculating operating costs based upon the average for the particular category of facility rather than estimating these costs as a percentage of investment costs. Another change is that the costs of the facility will be divided among the users of the facility based on each user's noncoincidental demands. The first change will result in a more accurate determination of of annual costs and the second in a more equitable allocation of those costs.

4. Integration of Resources Schedule, IR-1

a. Process

I believe that there is a need to develop uniform, postage stamp rates that respond to a wider range of rate design objectives than do the current rates. I believe it is consistent, therefore, that concurrent with the Federal Register Notices announcing the 1981 Wholesale and Transmission Rate Proposals, BPA issued a Notice of Intent to develop a new transmission policy, expected to be finalized by July 1, 1982. In order to allow BPA and its customers an opportunity to gain experience in the interim period, from July 1, 1981 to June 30, 1982, with broader, more flexible rate schedules, BPA's initial 1981 transmission rates included the IR-1 and IS-1 rates for customers who agreed to exchange their current FPT arrangements for interim 1 year arrangements to complement the IR-1 and IS-1 rates.

During the 1981 rate hearings the IR-1 rate schedule received considerable comment. In addition, to begin development of the new transmission policy, BPA conducted seven additional meetings outside of the formal rate hearings with interested customers and others, at which the IR-1 rate was discussed. Subsequently, the hearing officer ruled that the Transmission Rate record would be expanded to include the comments from those Transmission Policy Meetings on the IR-1 rate.

From this total record I have developed a revised IR-1 rate for interim, 1-year contracts that responds to many of the issues raised in the record. The resulting IR-1 rate design differs significantly from the IR-1 and IS-1 combination in the initial proposal. The issues that have not been resolved within these interim IR-1 arrangements will be the subject of continuing discussion and work toward development of the Transmission Policy and the 1982 Transmission Rate Schedules.

b. Derivation

The Network and Intertie IR-1 charges are shown in Table 8, TRDS. The unadjusted FPT revenue requirement derived from the COSA for Network and Intertie segments ($31.8 million and $1.8 million respectively) are adjusted for NF-1 and ET-2 revenues (Table 5, TRDS) to yield adjusted Network and Intertie revenue requirements of $27.8 million and $1.5 million, respectively.

The adjusted revenue requirements are collected by both contract demand and energy billing determinants (50 percent from each) for both the Network and Intertie schedules of the IR-1 rate. Dividing 50 percent of the Network revenue requirement by the total 1982 projected FPT Network contract demand yields an unadjusted unit charge of $1.975 per kilowattyear (Table 8, TRDS). Dividing the other 50 percent of the Network revenue requirement by the projected 1982 FPT energy yields an unadjusted unit charge of $.00053 per kilowatthour (Table 8, TRDS). Similarly, for the

Intertie, unadjusted unit charges are determined to be $3.418 per kilowattyear and $.00076 per kilowatthour (Table 8, TRDS).

To recover the projected rate option shortfall unadjusted unit costs are adjusted by the process described in Section VIII(B)(2). The adjusted unit charges (thus the IR-1 rate charges) are determined to be $2.099 per kilowattyear and $.00056 per kilowatthour for Network service and $3.629 per kilowattyear and $.00081 per kilowatthour for Intertie service (Table 8, TRDS).

c. Issues

(1) Choice of Billing Determinants

The choices of billing determinants for transmission rates are, of course, issues not limited to the Set B rates. The issues have been considered for all of BPA's transmission rate schedules. However, since the Set A rates I am offering in this 1981 rate filing are largely an update of existing rates, the choice of billing determinants for those rates is not of as much concern to the parties as is the choice for the new and untested Set B rates.

For the IR-1 rate I have chosen a combination of energy and contract demand as billing determinants with 50 percent of the total revenues collected from each determinant. In the initial 1981 proposal, BPA recommended that the billing determinant for both the IR-1 and IS-1 rates be the customer's coincidental monthly scheduled demand. Parties have expressed considerable concern suggesting that the IR-1 rates should contain both capacity and energy charges. Others suggested that if such a split were made and an energy determinant included, it would penalize high load factor customers, BPA would collect double its transmission income, or that revenues would have undesirable fluctuation depending on water conditions.

I believe that the combination of energy and capacity determinants is appropriate for two reasons. First, the combination reflects, to some extent, the 12 CP allocation factors that implicitly recognize an energy cost causation component. Second, the combination reduces the cost impact for infrequently used generating facilities that would result from billing on scheduled demand only. The combination substantially eliminates inefficient use of resources simply to avoid operating a particular resource for a small portion of a billing month in order to avoid a full month wheeling charge.

Regardless of the combination of energy and capacity billing determinants used, BPA's rates are designed to recover only the revenue determined by the COSA to be recovered from FPT rates. Thus, there is no merit to the concern expressed that the choice of billing determinants would collect double the required level of transmission revenues.

Comments also concerned use of coincidental versus noncoincidental demand and scheduled versus contract demand for the capacity billing determinant. I agree that the use of monthly noncoincidental demand might cause operating inefficiencies, rate continuity problems, revenue uncertainties for BPA, and cost uncertainties for some wheeling customers. In contrast use of coincidental demands would alleviate some of these problems, although possibilities for short run inefficiencies may still exist. Under coincidental demands, however, customers would lose control over the size of their own bills.

I believe that use of contract demand and energy is the most reasonable alternative to these scheduled demand options at this time. Contract demand and energy will reduce the probability of inducing short run inefficiencies while at the same time providing reasonable reflection of the cost causation factors identified in BPA's cost studies. Contract demand reflects the fixed nature of transmission system costs; BPA has incurred costs to integrate a resource even when that resource does not operate in a particular month. The energy component reflects the greater contribution to system diversity by low load factor customers and increased transmission costs incurred to reduce energy losses and to integrate baseload thermal generation.

On the use of contract demand, some customers expressed the opinion that the rates should be designed to allow them to specify their entire utility contract demand rather than using the sum of individual resource contract demands. They believe that simplicity of administration and flexibility of use will be lost with contract demand. I do not find utility-wide contract demand to be advantageous over individual contract demand nor do I find that simplicity of administration or flexibility of operation will be lost, although customers would not benefit from their own internal diversity.

A number of alternatives were advanced for determining the appropriate capacity/energy split. I find that this split is not susceptible to mathematical quantification. Since both factors are significant with neither of predominate importance, it is reasonable to recover half the revenue requirement from the demand charge and half from the energy charge.

On the question of distance as a billing determinant, I have decided that the IR-1 rates should not contain distance factors. There were numerous comments made throughout the hearing process and the interim contract meetings that distance should be included as a determinant. This was suggested primarily to keep short distance wheeling charges competitive and to avoid construction of duplicate facilities.

In an integrated network the distance between most resources and loads cannot be identified as a cost-causation factor because of the effects of displacement. The network provides benefits to all customers that do not relate to distance between resources and load. These include services such as transmission and generation reliability, generation backup, reduced losses and a market for nonfirm power. Using distance as a billing determinant would be inconsistent with the networkwide service being offered under IR-1.

I have decided not to utilize time-differentiated billing determinants in the Set B rate schedule. The initial proposal contained diurnal differentiation of the IR-1 rate so that no charge would be made for deliveries outside the weekday (and Saturday) peak period. The initial proposal did not time differentiate the IS-1 rate.

Comments during the rate hearing process suggested that the time differentiation of transmission charges conflicts with BPA's firm power sales contracts requiring computed demand customers to utilize their own resources first. This requirement does not conflict with time-differentiated wheeling rates because both power sales and wheeling utilize the FCRTS and therefore, substituting non-Federal power for Federal power does not lessen the need for transmission capacity. However, substitution of contract demand for scheduled demand as a billing determinant makes it less feasible to time-differentiate transmission rates. Consequently, BPA has not time-differentiated the IR-1 rate for this rate filing.

With respect to the final billing determinant issue, I have decided not to segregate network facilities by classes of use. In the initial proposal, BPA made no provision in the IR-1 rate for identifying specific facilities with particular customers. Comments throughout the hearings process suggested that BPA should recognize specific facility use and that the rate level should be dependent on the facility types used. However, specific facility use cannot be identified on an integrated network transmission system. To attempt to do so would defeat the purpose of the postage stamp IR rate with networkwide service.

In addition, I have decided not to give recognition in the form of credits or otherwise, to facilities in series with the FCRTS network. Comments during the rate hearing process suggested that credits should be made for utility-owned facilities. Such credits are inappropriate for the networkwide service offered under the IR-1 rate because any attempt to isolate and develop charges based on specific facilities factors likely would result in a constriction of service offered. I view networkwide flexible service offered at average cost to all users as an equitable and efficient way of charging for the use of an integrated network.

(2) Losses

I have determined that losses will continue to be addressed as a contract rather than a rate matter. Historically, BPA has treated losses in this manner, and the current contracts contain varying loss recovery methods that have been negotiated over the years. I understand and agree with the comments by the parties on the record to the effect that losses are an important factor in transmission costs. However, I believe that the contract process is the appropriate mechanism for addressing losses. Parties also indicated a need for a consistent, fair policy with respect to losses. I believe that the contracts involving the

IR-1 rate schedule are the proper forum for developing a consistent, fair loss policy, and BPA will continue its effort in this direction within the scope of the new transmission policy development.

(3) Services

The service provided by the IR-1 rate schedule is an attempt to offer uniform, networkwide service designed to give the customer flexible service and the benefits of the network as if it were his own system. The schedule permits multiple network delivery points without additional charges.

During the rate hearings and new transmission policy meetings, many questions were raised concerning specific provisions for the service under the IR-1 rate schedule. One particular area of concern is how BPA intends to treat incidental transactions. In particular, how will resources that operate for only a short period of time be treated. Essentially, I intend that under the IR-1 rate, resources that require a firm transmission path will be integrated regardless of the amount of time the resource may be operated. Customers also raised questions as to whether BPA's proposed rate schedules discourage incidental transactions. I find that consistent with past practices, incidental transactions under the Set A service require an additional charge, ET-2. However, Set B services are broadly defined and generally will allow network incidental transactions from all IR resources, at no additional charge provided that the amount of power integrated does not exceed the contract demand. In the case of incidental transactions between Set A and Set B customers, service may be provided to Set A customers that is not covered by their FPT contract. Therefore, an additional charge (ET-2) must be levied to the Set A customer when he receives incidental energy from a customer using Set B.

During the transmission policy meetings, the subject of parallel path scheduling was controversial. When a Pacific Northwest utility has a transmission line (or lines) from a resource to its load that has insufficient capacity to carry the full capability of the plant, then a portion of that plant must be scheduled over the Federal system. In these cases the contract demand will be the difference between the plant capability and the capacity of the utility's lines (assume, for example, plant capability of 1,000 megawatts, capacity of utility's lines of 400 megawatts, and contract demand of 600 megawatts).

In BPA's current arrangements, the amount that is scheduled over the Federal System during hours when the plant is operating at less than full capability affects the amount of losses to be returned to BPA. Under the IR-1 schedule the energy charge will also be affected by this determination. Currently, BPA has agreements that handle this problem in two different ways. Under the first method, the utility is given complete freedom to schedule up to its line capacity during all hours. In our example, if the plant were operating at 500 megawatts, 400 megawatts could be scheduled over the utility's own system and 100 megawatts over the Federal system.

The second method requires the utility to schedule a pro rata share of the generation over the Federal system each hour. Of the 500 megawatts in the example, 300 megawatts (600/1000 X 500) would be scheduled over the Federal system.

Parties argued that the pro rata method amounted to charging for inadvertent flow and would be inequitable because some Federal power also flows over non-Federal lines. They also argued that adoption of the pro rata method would in some cases be contradictory to methods developed during years of operating in parallel.

I have decided that the pro rata method is the fairest and most equitable method of recognizing the use of Federal facilities in parallel path situations. When two transmission systems interconnect, it is recognized that inadvertent flows will inevitably occur. In a situation where both utilities have sufficient capacity to carry their peak loads, such inadvertent flows are generally deemed to be of mutual benefit and no charges are made for facility use or losses. However, in a situation where a utility has purchased long term wheeling from BPA, BPA will install added transmission capacity sufficient to carry the contract demand amount. During hours when the purchaser's plant is operating at less than full capacity, a portion of the power will continue to flow over the Federal system. There is nothing "inadvertent" about this flow, because it is caused by the additional capacity added to provide the wheeling service. Therefore, it is appropriate to require a pro rata share to be scheduled over the Federal system for the determination of energy charges and losses.

BPA's current FPT contracts reflect many historical arrangements with regard to costs and services. The purpose of offering the IR-1 rate is to discard those historical arrangements to the extent that they are inequitable or inappropriate. Thus, I do not find that consistency with historical arrangements is necessary in adopting the pro rata share method.

Other issues raised with respect to services under the Set B rate schedules included: how will obligation energy be integrated under the IR-1 rate, and will BPA separately identify points of interconnection and delivery? I find that these issues are contract rather than rate matters and therefore will be addressed in the interim contracts and through development of the new transmission policy.

(4) Competitiveness

One of BPA's transmission rate design objectives is that the rates be competitive so that maximum use is made of the Federal facilities, while still assuring that BPA's revenue requirement is met. I believe that the interim IR-1 rate schedule meets this objective at this time. However, parties to this rate case have suggested that these rates are so high as to cause some utilities to construct their own parallel redundant facilities. I am therefore encouraging those customers to submit evidence that the facilities can be built at a lower annual cost than the wheeling charges and that they do not require the additional services of the Federal network.

The IR-1 rate schedule is designed based on average system costs rather than the specific requirements of individual customers, because the Integrated Network and the Intertie provide benefits over and above isolated point-to-point service. At this time, BPA is unable to quantify the cost and value of these benefits, which include stability, reliability of transmission, backup power sources, and a system for marketing surplus power. Any analysis of the alternative cost of building non-Federal facilities should consider these services of the Federal system.

IX. Wholesale Power Rate Design Study

A. Introduction

BPA conducted various studies to prepare the wholesale power rate proposal. This Wholesale Power Rate Design Study (WPRDS) combines the results of the COSA, LRIC Analysis and TDPA to develop the final rate schedules. Each step followed in developing the rate proposal is detailed herein. The wholesale power rate proposal includes the following rate schedules:

1. Priority Firm Power Rate Schedule, PF-1.
2. Wholesale Power Rate Schedule for Industrial Firm Power, IP-1.
3. Wholesale Power Rate Schedule for Modified Firm Power, MP-1.
4. Wholesale Firm Capacity Rate Schedule, CF-1.
5. Wholesale Emergency Capacity Rate Schedule, CE-1.
6. New Resources Firm Power Rate Schedule, NR-1.
7. Wholesale Nonfirm Energy Rate Schedule, NF-1.
8. Reserve Power Rate Schedule, RP-1.
9. Wholesale Firm Energy Rate Schedule, FE-1.
10. Special Industrial Power Rate, SI-1.

Electric utility ratemaking involves consideration of several rate design objectives. BPA, as a Federal power marketing agency, is a non-profit organization having different rate objectives than investor-owned or consumer-owned utilities. BPA is obligated to collect sufficient revenues to recover all its costs and to seek the lowest possible rates for consumers consistent with sound business principles.

The basic rate design objectives followed in designing BPA's wholesale power rates include: (1) ensuring adequate revenues to meet its repayment obligation; (2) meeting the revenue requirements while distributing the burden in an equitable manner among recipients of the service; (3) designing rates to encourage conservation and minimize environmental impacts; and (4) designing rates to encourage efficient use of the FCRPS by reflecting costs incurred and benefits received. Additionally, consideration is given to rate continuity, ease of administration, revenue stability, and ease of understanding.

B. Adjustment of Cost Data

In developing individual schedules, BPA made several adjustments to the COSA results based on findings of other rate design studies and the rate design objectives. Table 1 of WPRDS is a summary of COSA's allocation of tramsmission costs. Table 2 of WPRDS shows the generation costs to be allocated from COSA.

1. Application of Time-Differentiated Pricing Analysis

Long run incremental costs and embedded costs are time differentiated in the TDPA. Although rates are based on average costs, offpeak generation capacity and transmission costs are set at zero to reflect the fact that the TDPA indicates that long run incremental capacity costs are incurred solely in response to additional peak period usage (Table 3, pp. 1 & 4, WPRDS). Generation capacity costs are apportioned to the winter and summer weekdays including Saturday based on the relative distribution of embedded costs to these time periods.

Energy costs associated with the three resource pools are apportioned to the September through March (winter) and April through August (summer) periods based on the distribution of Federal base system energy costs (Table 3, WPRDS). Specifically, 62.8 percent of costs are assigned to the winter period and 37.2 percent to the summer period.

BPA received four types of comments on these decisions. The comments included: (1) the logic for including Saturday in the peak period is invalid; (2) BPA has not sufficiently incorporated the structure of long run incremental cost in the design of time-differentiated rates; (3) demand charges based on time-differentiated noncoincidental peaks do not properly reflect cost causation; and (4) the legitimacy of time-differentiating new resource and exchange costs on the basis of a Federal base system analysis is open to criticism.

The issue of whether daytime Saturday hours are peak or offpeak is a polemic one. An empirical analysis of Federal firm hourly loads for FY 1975-1979 showed that the fifteen peak hours for Saturday averaged much nearer the same average for Sunday than for any of the five weekdays (Monday through Friday). Weekday peak hours averaged 1661 megawatts above Sunday's while Saturday peak hours were higher by only 487 megawatts. This is based on a weekday peak period average of 10352 megawatts. Consequently, Saturday was grouped with Sunday, and, since Sunday is traditionally offpeak, daytime Saturday was deemed offpeak.

This is a different statement than saying that Saturday is identical to Sunday or that daytime loads on either day are less than average nighttime loads. Statistically, this analysis showed that Saturday's peak was greater than Sunday's, but closer to Sunday's than weekday's. A sensitivity analysis on FY 1978 firm loads for the 1979 rate filing demonstrated that including Saturday in the peak improved the percentage of hours correctly classified to peak, secondary peak, and offpeak time periods. Clearly, Saturday daytime belongs to an intermediate peaking period.

Theoretically, unit costs can be different for every hour of the year and ideally, the price for capacity can be different for every hour of the year. One rate objective, ease of administration, is served by grouping hours into homogeneous groups. For both the 1979 and current rate filing, three wholesale capacity rate periods for embedded costs have emerged: winter peak, summer peak, and offpeak. Saturday must be classified as peak or offpeak to avoid complicating the periods. I have decided to allocate no costs to the offpeak period which is appropriate for nighttimes and

Sundays. However, this is not suitable for Saturday. A charge of zero for Saturday capacity might result in enough load shifting to warrant reclassifying it to the peak period in the future. This would be inconsistent with the time-differentiation objective of defining the peak periods broad enough to allow for shifts in loads without shifting the peak outside the peak period.

Since there is no discussion in the Official Record of a distinct Saturday rate period or of a methodology for determining associated costs, the only viable option is to classify Saturday with Monday through Friday and charge the established peak rates. I do not consider this issue to be completely solved. However, in view of the absence of definitive empirical work, for purposes of continuity of rates and to prevent conflict with existing contracts, I have decided to leave Saturday hours 7 a.m. to 10 p.m. in the peak period.

The second comment suggested that the energy differential based on storage costs is inappropriate since storage costs are an embedded cost consideration. The proposed energy differential is indeed based on embedded cost considerations. It should be noted that incremental energy costs are not time-differentiated because incremental energy resources are operated in response to increases in demands for energy regardless of hourly or seasonal considerations, and to reflect the fact that no new hydro storage facilities are planned. Historical usage of the existing hydro storage facilities indicates that embedded hydro storage costs are a basis for an embedded cost differential.

I do not agree with the California Energy Commission's contention that a kilowatthour energy charge more fairly recovers capacity costs than a time-differentiated demand charge based on individual customer's periodic peak usage. There is some truth in the Commission's position that, for a hydro system, peaking capability depends to an extent on the duration of previous demands as well as the hourly peak level of these demands. However, I believe sustained peak demands over time contribute more directly to energy requirements. Complete reliance on only a kilowatthour charge would ignore differences in capacity costs imposed by different customers consuming the same kilowatthours but at different rates of peak level service.

With respect to the criticism of the time differentiation of the new resource and exchange costs according to the results of a Federal base system analysis, the alternative was to not time differentiate them. The technical mix of the exchange and new resources and the timing of their associated loads are not expected to duplicate the technology and load shape of the historic FCRPS. However, there is no documentation on which to base a time-differentiation analysis of these resource pools other than the analysis of the Federal base system. Tables 4, 5 and 6 of the WPRDS show the allocation of costs to customer classes after time differentiation.

2. Excess Revenues

Three rate schedules, NF-1 nonfirm energy, CF-1 firm capacity, and ET-2 energy transmission, produce revenues in excess of allocated costs. Revenues from sales under the NF-1 rate that correspond to the transmission component of the rate plus revenues from ET-2 have been credited to transmission capacity costs. The remainder of the NF-1 excess revenues and the CF-1 revenues resulting from the sustained peaking charge and from the seasonal capacity charge have been credited to generation capacity. In addition, the generation portion of the NF-1 average sales rate has been applied to the DSI top quartile sales. Finally, that portion of new resources load that will be served by hydro because purchase power will be displaced under average water conditions has been priced at the Federal base system generation portion of the NF-1 average sales rate. Derivation of the excess revenues can be found in Table 7 and Table 17 of the WPRDS and Table 2, TRDS.

Excess revenue adjustments of the final rate proposal differ in five aspects from the adjustments in the initial proposal. The changes involve: (1) the average NF-1 sales rate; (2) crediting of revenues to new resources capacity costs as well as Federal base system capacity costs; (3) crediting of revenues from new resources purchase power that will be displaced with hydro under average water conditions; (4) excess revenues from the CF-1 seasonal capacity charge and sustained peaking charge; and (5) application of the credit to capacity costs for the summer period only.

An average NF-1 sales rate of 9.6 mills per kilowatthour was calculated for the final proposal. On the basis of a staff analysis of monthly secondary energy sales, and monthly operation of thermal resources and power purchases under average water conditions for FY 1982, the 7.5 mills per kilowatthour figure in the initial proposal was changed to 9.6 mills. Of the 9.6 mills per kilowatthour, 7.6 mills per kilowatthour corresponds to the generation component of NF-1 and 2.0 mills per kilowatthour corresponds to the transmission component.

The second change in the final proposal involved crediting nonfirm revenues to the costs of new resources capacity as well as to the costs of Federal base system capacity. Nonfirm energy sales will be served by generation from the new resources pool as well as the Federal base system. Staff determined that of the generation portion of the average NF-1 rate of 7.6 mills per kilowatthour, 5.5 mills per kilowatthour is due to the utilization of Federal base system resources and the remaining 2.1 mills is due to the utilization of new resources. Thus, the Federal base system pool is credited with 5.5 mills for each kilowatthour sold under the NF-1 rate and 2.1 mills is credited to the new resources pool to reflect the contribution from each pool. These same rates also were applied to DSI top quartile service.

The 5.5 mills per kilowatthour associated with the utilization of Federal base system resources was used to price the hydro that displaces purchase power for serving the new resource load under average water conditions. This includes the Boardman purchase that is used to serve the new resources load and the portion of purchase power that will be used to serve the new resources deficit. These purchases will be displaced with hydro under average water conditions.

The 2.0 mills per kilowatthour portion of the 9.6 mills average NF-1 rate was applied to total NF-1 sales to determine the revenues to be credited to transmission costs. In addition to the transmission component of the NF-1 sales, excess revenues generated by the ET-2 energy transmission rate were applied to transmission costs. The total excess transmission revenues were first reduced by the amount of intertie costs credited to nonfirm service. The transmission portion of wholesale power costs was credited with $26.814 million and the wheeling rates received $4.214 million (Table 8, WPRDS).

The fourth change in the crediting of excess revenues adjustment concerns the CF-1 rate. Previously, no revenues were forecasted to be collected from the CF-1 sustained peaking charge based upon experience under the 1979 F-7 firm capacity rate. However, assumptions concerning the calculation and basis of the charge have been altered (Section IX(C)(3)). BPA is now assuming that revenues will be collected in excess of allocated costs because of the sustained peaking charge. Therefore, the excess revenue is allocated to Federal base system capacity costs.

The manner in which the CF-1 seasonal capacity charge was calculated also has been changed. The current F-7 seasonal capacity charge was escalated by applying a 20.9 percent inflation factor to that charge. Thus, the seasonal capacity charge will produce revenues in excess of allocated costs. Excess revenues of $1.126 million have been credited to Federal base system generation capacity costs excluding seasonal capacity (Table 17, WPRDS).

Overall, a credit of $91.421 million was applied to FBS capacity costs and $29.857 million was applied to the new resources capacity costs. The credits reflect a reduction for metering and billing costs that had been allocated to nonfirm service.

The final change in the methodology is the crediting of revenues to summer generation capacity costs (Table 8, WPRDS). In the initial proposal revenues were credited to summer and winter generation capacity costs on a pro rata basis. Thus, this change places more emphasis on the LRIC Analysis and TDPA than previously. The crediting of excess revenues to capacity costs reflects the incremental cost relationship between capacity and energy, developed in the LRIC Analysis. The cost relationship between capacity and energy changes as BPA purchases the output of new thermal plants. By comparing the results of the COSA with those of the LRIC Analysis, this changing relationship is evident. These studies show that although all costs are increasing, the costs of supplying energy are increasing at a faster rate than the costs of supplying new capacity. Results from the LRIC Analysis indicate a demand rate of $8.11 per kilowattmonth (Table 12, LRIC Analysis) and an energy rate of 61.76 mills per kilowatthour (Table 3, LRIC Analysis). Unadjusted results from an analysis of the Federal base system costs indicate a demand rate of $2.57 per kilowattmonth and an energy rate of 5.83 per kilowatthour (Table 12, TDPA). The ratio of the LRIC demand rate to the average demand rate is 3.1 to 1, while the ratio of the LRIC energy costs to the average energy costs is 10.6 to 1.

A comment was received suggesting that excess revenues be credited to energy instead of capacity. The reason offered was that NF-1 sales are energy-only transactions and have no effect on system peaking capability now or in future years. However, as indicated above, I believe that it is most important to reflect the changing cost relationship between capacity and energy by sending price signals to BPA's customers. One party commented that residential consumers would not receive price signals or would receive inappropriate signals through their retail electric rates. While BPA has no control over the rate structures of its utility customers, I believe that BPA has the responsibility to reflect its costs in wholesale rates structures. To the extent that utilities reflect this price signal in their rates, the ultimate consumers will receive the signal and have the opportunity to modify their behavior with regard to electricity consumption.

3. Fixed Contracts

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 total fixed contract revenue deficiencies, adjusted for revenue from sales of nonfirm energy, are \$53.624 million, of which \$12.698 million is classified to capacity and \$40.926 million is classified to energy (Table 9, WPRDS). The impact on average unit costs for power sales customers served by Federal base system resources is an average increase of \$0.07 per kilowattmonth for generation capacity and 0.6 mills per kilowatthour for energy (Table 10, WPRDS).

a. Canadian Treaty

BPA incurred certain obligations through the "Treaty between the United States of America and Canada Relating to the Cooperative Development of the Water Resources of the Columbia River Basin" to generate capacity and to transmit capacity and energy. Contracts resulting from this treaty obligate BPA to generate Supplemental and Entitlement capacity at a fixed rate of \$5.50 per kilowattyear and to transmit Supplemental capacity and Columbia Storage Power Exchange (CSPE) power at a fixed rate of \$1.50 per kilowattyear. Although the rates are fixed, the amounts of power to which they apply gradually declines until April 1, 2003, when the contracts expire.

The revenue deficiency associated with all CSPE transactions for FY 1982 is functionalized to generation and classified to both capacity and energy in the same manner as baseload hydro plants (Table 9, WPRDS). 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 (Table 10, WPRDS). This process results in allocation of a portion of the Canadian Treaty revenue deficiencies to all capacity and energy sales customers served by Federal base system resources. The Canadian Treaty results in an increase in the firm capacity and energy capability of the Federal base system and, thus, power sales customers served by Federal base system resources benefit from this increased capability. Transmission customers are not allocated a direct share of the deficiency because they do not receive any direct benefit from the Canadian Treaty.

b. Capacity/Energy Exchange

The capacity/energy exchange contracts obligate BPA to provide service for which the contracting party often provides a reciprocal service instead of a direct payment. Under these 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), certain 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. Because energy customers receive the benefits of the firm power resources provided by these contracts, the revenue deficiency is classified to energy (Table 9, WPRDS). The deficiency is prorated to rate periods on the basis of the energy allocation factors (Table 10, WPRDS).

Issues regarding the appropriate treatment of the revenue deficiency have been raised. It was suggested that the deficiency should be classified to capacity based on cost of service and cost causation considerations. However, I believe that it is most fitting to classify the revenue deficiency to the energy customers who benefit from these contracts. The suggestion also was made that the deficiency be treated by subtracting it from nonfirm energy excess revenues. Again, it appears to be most equitable to assess the deficiency to customers who receive the benefits. In addition, I feel that it is of primary importance to provide price signals to BPA's customers that reflect the results of the LRIC Analysis.

The final comment questioned the amount of the revenue deficiency. The concern was expressed that this amount may be overstated by not accounting for energy payments when the return of energy is not required. This problem is avoided by accounting for the energy payment in the secondary energy analysis, and thus, in the nonfirm energy excess revenues.

4. Value of Reserves

BPA's firm power sales contracts with the DSI's provide BPA with certain rights to restrict power deliveries to these customers. These restriction rights provide reserves to the Federal System that otherwise would have to be provided by generation resources or additional transmission facilities. In the 1974 and 1979 rate filings an availability credit was given as compensation for BPA's restriction rights on DSI load. The 1979 availability credit was based on the costs of power to replace expected restrictions and was not based on an analysis of the value of the reserves being provided. The Regional Act in Section 7(c)(3) states that BPA will adjust the DSI's rate with consideration for the value of the reserves they provide. Therefore, BPA has conducted a value of reserves study and computed a reserves credit that totals $76 million in 1982.

The value of reserves study was based on the cost of providing the same amount of reserves through alternative generation and transmission facilities. I decided that BPA's current LRIC results should be used to represent BPA's alternative cost of providing these reserves because the DSI contracts are currently being renegotiated and the mutual decision of providing reserves through restriction rights has to be made again. However, while the value of the reserves is at the margin, it would be inequitable to grant the DSI's a reserve credit based on marginal costs because the DSI's and BPA's other customers are charged for power on the basis of average embedded costs rather than marginal costs. A reserve credit based on marginal costs would be, I believe, a windfall to the DSI's and unnecessarily burdensome for BPA's customers who are allocated the costs of the reserve credit.

Therefore, the value of reserves, determined to be $521 million, was reduced by the ratio of average costs to marginal costs resulting in a reserve credit of $76 million (See Table 11, WPRDS). This reduction also reflects the sharing of benefits between the DSI's and all other customers that was mentioned in the Senate report on S.885. In computing the ratio, the average cost of power used was the average cost of Federal base system resources. Using any other measure of average cost (such as the DSI rate) would be inequitable to the customers served by Federal base system resources. In computing the operating and stability reserves credit in the initial proposal, incorrect ratios were used that have been corrected in the final proposal.

In the initial proposal the reserve credit was classified to capacity and energy according to the amount of capacity and energy reserves offered by the restriction rights and the average cost of each. For the final proposal a further adjustment was made to reflect the relationship of capacity and energy on the margin (Table 11, WPRDS). Since BPA's marginal cost of energy is increasing faster than capacity (as reflected in the LRIC analysis), this further adjustment was made in order to send the proper price signal. Namely, the cost of energy reserves is rising faster than the cost of capacity reserves. This results in classification of $62 million to energy and $14 million to capacity.

The costs of the reserve credit were allocated to all firm power customers. BPA's reserves requirement is based on serving firm loads including three quartiles of DSI load. BPA also purchases generation or transmission facilities to supply these reserves (although the purchases as in the case of the restriction rights on DSI loads may not be actual generation and transmission facilities, but rather reflect the cost of actual generation and transmission facilities). Thus, it seems most appropriate that all firm power customers including DSI firm loads should be allocated costs of the reserve credit (Table 12, WPRDS).

I recognize that the DSI's are concerned that they will be paying for reserves twice, once through the IOU exchange and once through the reserves credit. However, the DSI's are paying for BPA's reserves. The IOU exchange is one of BPA's resources for which BPA supplies reserves. The fact that IOU exchange costs include reserve costs is a consequence of the way this resource was created.

5. Low Density Discount

A low density discount (LDD) is included in the PF-1 Priority Firm Power Rate Schedule pursuant to Section 7(d)(1) of the Regional Act. This discount has been instituted to aid customers with low system densities in avoiding adverse impacts on retail rates. This discount is available to all customers purchasing under the PF-1 rate whose entire systems meet the eligibility criteria. The discount will be applied to the monthly charges for priority firm power. The revenue deficiency that results from granting the discount is allocated to the cost of energy from Federal base system resources to reflect the results of the LRIC Analysis. The amount of the discount will depend on either 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 the purchaser's ratio of residential consumers per mile of distribution line.

The discount will be: (1) 7 percent if the ratio is equal to or less than 15 kilowatthours per dollar of net investment or if the number of consumers per mile of line is two or less; (2) 5 percent if the ratio is greater than 15 and equal to or less than 25 kilowatthours per dollar of net investment or if the number of consumers per mile of line is four or less; and (3) 3 percent if the ratio is greater than 25 and equal to or less than 35 kilowatthours per dollar of net investment or if the number of consumers per mile of line is six or less.

The customer will receive the highest discount for which the utility qualifies. In addition, no customer with more than 10 residential consumers per mile of distribution line may qualify for a discount regardless of the investment ratio. This latter restriction was not included in the initial proposal and has been added as a result of comments received during the hearing process. The eligible customers are listed on Table 13, WPRDS. The total discount amounts to $6.599 million.

Other comments were received concerning eligibility requirements and criteria for calculating the discount. Some parties asserted that only preference customers should receive the LDD. However, there is nothing in the legislative history of the Regional Act or in the Regional Act itself that would limit the discount to preference customers only. The legislative history of S. 885 indicates that the LDD was proposed as an amendment by Senator Jackson and was to be offered specifically to public bodies and cooperatives. The Senate Committee on Energy and Natural Resources substituted the words "of the Administrator's customers" for the words "to public bodies and cooperatives." It is a well-established rule of statutory construction that "the rejection of an amendment indicates that the legislature does not intend the bill to include the provisions embodied in the rejected amendment" (2A Sands, Sutherlands Statutory Construction, Section 48.18 (4th Ed. Supp. 1981)).

I do not find it necessary to include specific criteria to disqualify customers as one comment suggested since staff will review and determine eligibility of all customers for the LDD at least annually. The LDD also will be evaluated regularly to determine whether the criteria should be altered and whether the discounts should continue to be offered.

I consider the low-density discount to be a rate rather than a contract matter, as was suggested in the hearings, because of the need to review the discount periodically and the fact that the LDD is included in Section 7 (the rate directives section of the Regional Act). Another party recommended the inclusion of an additional criterion involving the comparison of residential power costs of neighboring utilities. However, it is not the intent of the Regional Act to eliminate rate disparity among neighboring utilities and evaluation of this criterion would be an unjustified administrative burden.

The final two categories of comments concern the appropriateness of offering a discount and suggest alternative methodologies for the treatment of the revenue deficiency resulting from granting the discount. With regard to the first issue, I have determined that LDD's are appropriate to avoid adverse impacts on residential customers of utilities with low system densities. The two methodologies suggested are the collection of the deficiency through capacity charges and crediting the deficiency to the NF-1 excess revenues. Although other methods have been considered, I believe it most important to reflect the incremental cost relationship between capacity and energy that was developed in the LRIC Analysis. Therefore, the costs were recovered through the FBS energy charge (Table 14, WPRDS).

6. At-Site Power

At-site power is made available under PF-1, IP-1 and MP-1 rate schedules for those customers that presently purchase power under existing contracts at the at-site rate. These customers are entitled by contract to an adjustment of $0.257 per kilowatt month. This adjustment is about 25 percent of the proposed uniform transmission component of the wholesale rate schedules and is less than the 46 percent adjustment originally developed for the Bonneville Project in 1938. The present at-site customers are adjacent to The Dalles, John Day, Hungry Horse, and Ice Harbor Projects. The conditions at these projects do not correspond to those existing at the Bonneville Project in 1938, that were the basis for the $3.00 per kilowattyear adjustment. I am convinced that the at-site delivery no longer provides any significant reduction in the transmission system required to integrate a project. Therefore, I do not plan on extending the at-site provisions for existing customers at the end of the contract term nor entering into any new agreements for at-site power.

An adjustment has been made to recover the $1.827 million dollars that are given as an at-site discount. This deficiency is recovered from all users of the transmission system. Calculation of the amount of at-site discount is shown on Table 15 of the WPRDS. The adjustment to recover the amount of the discount is shown on Table 16 of the WPRDS.

Two of the at-site customers, who had to install or acquire from BPA all the transmission facilities from the at-site point-of-delivery and pay for losses on those facilities, now recognize that the costs of these facilities exceed, or will soon exceed, the economic benefits of the at-site adjustment of the rate schedule. The at-site customer, in effect, is or will be paying a premium. While I conclude that these existing customers should continue to receive no more than the credit required by the contract provisions, I plan on negotiating, when requested by the customer, new contract terms that permit the customer to eliminate the at-site provisions of their contracts.

7. Equalization of Demand

The final adjustment to the costs assigned to the service classes is the equalization of demand charges. The first part of the process is the equalization of Federal base system resource capacity costs. The costs of transmission capacity allocated to priority firm power, industrial firm power and annual capacity are summed and divided by the appropriate billing determinant. This process is repeated for summer and winter generation capacity. The results are the equalized unit charges of \$ 1.17 per kilowattmonth for summer capacity and \$ 3.07 per kilowattmonth for winter capacity (Table 19, WPRDS).

After the adjustment of the seasonal demand rates described in the next section, the unit capacity costs of other resources are then set equal to the Federal base system unit capacity costs (Table 21, WPRDS). This equalization adjustment results in an increase in total capacity costs above those allocated to the new resource rate and industrial firm power rate. Thus, the energy cost associated with each rate is decreased to compensate for the capacity cost increases.

Comments were received that the equalization of the demand charges nullifies the COSA results and thus, ignores the cost basis of the rates. The effect of the adjustment is to reduce the industrial firm power rate and overprice the cost of the IOU exchange resources to the benefit of the DSI's. The adjustment also increases the priority firm rate to the detriment of public agencies and the IOU residential and farm customers. However, the adjustment, permitted by Section 7(e) of the Regional Act, was applied to demand charges that were relatively close in magnitude. Unlike the initial proposal, the final allocation of costs to the DSI's results in a slightly lower unit demand charge than other service classes. Thus, the adjustment does not significantly impact the rates. In addition, the provision of a uniform rate for all capacity charges facilitates the administration of the rates and provides for continuity.

8. Adjustment of Seasonal Demand Rates

In reviewing the results of the adjustment to equalize the demand costs of the Federal base system users, I found the relationship between the summer and winter capacity increases to be unacceptable. The summer capacity cost indicated a decrease over the current summer demand rate, while the winter capacity cost increased 56 percent over the current winter demand rate.

Because of rates of inflation between 1980 and 1982 the decrease in the summer rate in real terms was over 20 percent. For purposes of equity and to avoid encouraging additional capacity usage I determined that the current summer capacity charge should be increased by no less than the rate of inflation between 1980 and 1982. As a result, the real cost of summer capacity when compared with the general level of inflation in the economy is the same under the 1979 rate and the 1981 rate. This results in a summer demand charge of $1.44 per kilowattmonth. Costs were removed from the winter capacity component and placed in the summer capacity component to increase the summer demand rate. This results in a winter demand rate of $2.80 per kilowattmonth. Table 20 of the WPRDS shows the result of this adjustment. There is a 21 percent increase in the summer demand rate and a 44 percent increase in the winter demand rate.

9. Boardman Adjustment

In the development of the rates for the initial proposal, an adjustment was made in the rate design process to reflect my policy concerning displacement of high cost Federal resources relative to the utilization of Federal excess resources to serve the top quartile of the DSI load. The Administrator must operate the Federal system to serve firm loads in the most economical manner consistent with statutory requirements. For the final rate proposal, I am assuming that BPA acquires a share of the Boardman coal plant. I will use any available Federal resource to displace the operation of a high decremental cost resource such as Boardman, unless it is economical to continue operating the resource and market its output at a rate higher than the decremental cost of the resource.

In the initial proposal, staff determined the amount of additional average megawatts of service available to serve the top quartile of the DSI's if Boardman were operating rather than being displaced. The costs associated with this additional operation of Boardman were removed from the costs assigned to the New Resource Firm Rate and were added to the costs assigned to the DSI rate.

A similar analysis was performed for the final proposal. However, the additional service to the top quartile realized by continued operation of the Boardman plant using our updated study was so miniscule that I have chosen not to make an explicit adjustment to the rates to reflect this, as I did in the initial proposal. My policy remains the same in that I will determine how to best operate the Federal system using the economic criteria I described above.

10. Streamflow Conditions Adjustments

A streamflow conditions adjustment was included in the PF-1, IP-1, MP-1, NR-1, RP-1, and FE-1 rate schedules in the initial wholesale rate proposal. Monthly adjustments were to be applied to all firm energy sales if actual streamflow conditions since the preceding July 31, plus the forecasted streamflows for each month, January through June, for the remainder of the year through July 31, indicated below average streamflow conditions.

BPA, subject to FERC approval, would assess a charge limited to the lower of: (1) the amount BPA actually spends to purchase power in excess of the amount budgeted for power purchases as reflected in the development of BPA's wholesale power rate schedules; or (2) an amount determined by multiplying the then-current price of oil-fired thermal generation times the excess, if any, of the computed FCRPS generation under average streamflow conditions over the computed FCRPS generation under actual plus forecasted streamflow conditions.

Although planning criteria for firm power requirements are made on the basis of critical water conditions, actual rates are established on the basis of average water conditions. Assuming that additional short term purchase power would be required to offset below average streamflow conditions, it is possible that power supply costs could exceed BPA's revenues. Revenues from nonfirm energy sales in good water years will not offset additional costs incurred because of lowered revenues in poor water years. During the good water years, BPA will make greater-than-forecast nonfirm energy sales. Nonfirm energy sales in poor water years will be quite low to nonexistent and additional high cost power purchases will be necessary.

If more revenues are collected than forecast in a given year, these revenues will be applied to amortization of the Federal debt resulting in a lower revenue requirement in subsequent years than would otherwise be necessary. However, if poor water conditions occur during a specific year, there is no mechanism built into BPA's current rate structure that could adjust for greatly increased purchase power expense.

The major purpose of the streamflow adjustment as included in the initial proposal was to provide a mechanism to alleviate the short term cash flow problem created by poor water conditions. In the past, BPA has responded to this situation by deferring payments to the Treasury for the amortization of the Federal investment in power system facilities and, if needed, for accrued interest on the Federal investment. This deferral constitutes a borrowing of funds for which principal and interest must be repaid. Any amounts deferred plus interest are subsequently included in determining BPA's future revenue requirements and need for rate adjustments.

The streamflow adjustment in the initial proposal did not require BPA to utilize any of its deferral capabilities prior to imposing a streamflow conditions adjustment. Several parties argued that this was inequitable, in that no credits would be given to the firm energy customers when water conditions and revenues were better than projected. Admittedly, it is still possible for BPA to tolerate significant revenue fluctuations from year to year by deferring some interest payments and planned amortization payments. In determining the appropriateness of including the streamflow adjustment in the final rate schedules, this deferral capability was taken into account. It seemed appropriate to add an additional dollar cushion to the budgeted purchase power amount that BPA would have to absorb prior to imposing a streamflow conditions adjustment.

An analysis of BPA's potential cash flow situation during the test year, assuming critical water conditions, shows that BPA's deferral capabilities would be sufficient to cover all but the most severe cash shortfall. The results of this analysis, along with consideration of the concerns expressed by customers about the potential adverse impact of the adjustment on an individual utility's financial viability, have led me to recommend that the streamflow conditions adjustment be removed from the rate schedules in the final proposal. Staff will continue to analyze such a mechanism, and will more thoroughly identify and assess how it could be designed and implemented, so that it can be addressed in a future rate filing.

11. Transformation Charge

For the 1979 Wholesale Power Rate Filing, the Administrator determined (1979 Administrator's Record of Decision, November 1979, pp. 46 and 47) that it was inequitable to isolate and develop a separate charge for lower voltage delivery facilities. He found there is very little correlation between higher total transmission costs and lower delivery voltages as the delivery location, size of load, reserve capacity, chronological date of initial service, and local transmission voltage each have some impact on total transmission costs. Even though the segmentation in the 1979 COSA developed costs for delivery facilities, the Administrator eliminated the low voltage facility charge in 1979 after it was in effect for only one 5-year rate period (1974 - 1979). As BPA staff explained in the 1981 Rate Hearings (Transcript, pp. 1816-1818), the 1981 rate proposal does not have any specific discussion of transformation charge or high voltage discount because the subject was fully discussed in previous public involvement programs.

Although the 1981 COSA continued the same segmentation as the 1979 COSA which developed costs for lower voltage delivery facilities, there is still no information developed showing that a separate low voltage delivery facility charge is more appropriate or different than a high voltage delivery facility charge.

I am aware of the concerns of some larger customers who disagree with the Administrator's decision in 1979 and want to reintroduce the low voltage facility charge in 1981. These concerns were raised and summarized in at least two final briefs that state, among other things,

> "BPA's self-serving comments should be stricken [from the 1981 Staff Evaluation of Official Record] and disregarded" (Public Generating Power Pool, June 3, 1981).
>
> "The failure of BPA to consider the reintroduction of the transformation charge operates to penalize, through higher rates, customers who have installed their own transformation facilities (Snohomish County Public Utility District No. 1, June 2, 1981)."

I am also aware that many smaller customers have indicated on the record that they agree with the Administrator's decision in 1979.

For the 1981 Wholesale Power Rate Proposal, I conclude that the delivery facility costs should be combined 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. Neither the studies done by me nor those presented by the utilities support a separate charge for low voltage facilities. There is insufficient evidence on the record to support adoption of a transformation charge.

BPA will continue to consider specific requests from customers who believe they were financially affected because the inclusion of a transformation charge in BPA's rates, between 1974 and 1979, encouraged them to construct transformation facilities. BPA will mitigate any net adverse impacts that can be substantiated.

C. Derivation of Wholesale Rate Schedules

1. Priority Firm Power Rate Schedule, PF-1

a. Description

The PF-1 rate schedule replaces the EC-8 rate schedule that became effective on December 20, 1979. The PF-1 rate schedule, like the EC-8 schedule, is available for purchase of firm power for resale or for direct consumption by public bodies, cooperatives, and Federal agencies. It also can be used by investor-owned utilities participating in the exchange under section 5(c) of the Regional Act. The PF-1 schedule was derived according to the steps which are described in the preceding sections on time differentiation and adjustment of cost data. The demand charge is time differentiated on both a daily and seasonal basis. The peak, secondary, and offpeak periods are the same as in the EC-8 rate schedule. The peak season demand charge is in effect from December through May, Monday through Saturday, 7 a.m. to 10 p.m. The secondary season demand charge is in effect from June through November, Monday through Saturday, 7 a.m. to 10 p.m. The two energy seasonal periods are also the same as in the EC-8 rate schedule. There is a seasonal energy charge based on an analysis of the costs of seasonal hydro storage. The two energy seasonal periods are April through August and September through March.

The rate contains a power factor adjustment and a demand charge adjustment for at-site customers. The PF-1 rate in the initial proposal contained a streamflow conditions adjustment designed to enable BPA to more closely meet its revenue requirement should less-than-average streamflow conditions occur. This adjustment does not appear in the final PF-1 rate schedule. The reasons for eliminating this adjustment are discussed in Section IX(B)(10).

A final adjustment in the PF-1 rate schedule provides for the granting of a predetermined low density discount to be applied monthly to the charge for power to eligible priority firm customers. This adjustment is included pursuant to Section 7(d)(1) of the Regional Act that requires the Administrator to apply discounts to the extent appropriate to the rates for customers with low system densities in order to avoid adverse impacts on their retail rates. Further discussion of the low density discount is included in Section IX(B)(5).

The proposed PF-1 schedule has four sets of billing factors: one for customers who are participating in the exchange under section 5(c) of the Regional Act, one for customers who are contractually limited to the amount of capacity and/or energy they can purchase from BPA, one for customers designated by BPA to purchase on a computed demand basis because operation of their resources can adversely impact the Federal System, and one for customers that may or may not have resources available to them, but if they do have resources, they do not adversely impact the Federal System. In the latter two cases, BPA is obligated to provide power to meet the utilities' requirements or provide an amount on which the parties agree.

b. Computed Demand

A utility that is designated to purchase on a computed demand basis has an ability and an obligation to produce an assured resource capability because of the coordinated operation of resources by utilities in the Pacific Northwest. This assured resource capability is determined based on critical water conditions. BPA is obligated to supply firm power to these customers equal to the amount by which each customer's firm load exceeds its assured resource capability (net requirements). The difference is the customer's "computed demand." BPA may deliver less than this limit when the customer generates in excess of the assured capability of its firm resources (e.g., when waterflows are in excess of critical waterflows). In these cases, the customer has the option of selling its excess generation and relying on BPA to deliver the computed demand. The computed demand billing factors provide BPA with a means of assuring that the amount of firm power delivered to a customer does not exceed the customer's net requirements. BPA is thereby assured that the customer is using its own assured resources to meet its load and is selling its own excess resource capability, not BPA's.

A computed demand customer's "net requirement" may be different for capacity than for energy. BPA, therefore, defines peak computed demand (PCD) and energy computed demand (ECD), and determines the customer's monthly rights to firm power based on these two amounts.

Based upon an inequity that developed between the PF-1 and NR-1 rates and the terms of computed demand contracts being negotiated, I have deleted the 60 percent ratchet for energy computed demand billing factors. Contracts providing for the sale of power to utility customers under these rates prohibit resale of power purchased from BPA to customers other than the consumers and customers to which the utility normally sells. Because of this prohibition, the billing factors in the previous rate schedules occasionally resulted in utility customers being denied the right to take power for which they were obligated to pay.

Although "ratcheted demand" charges are a commonly used method of assuring the wholesale power seller that it will collect revenue to repay its fixed investments, BPA believes that it will be able to market to others the power not billed under ratcheted demands. Alternatives would be to continue to charge customers for power up to the ratcheted demand and to resell that power. BPA believes that eliminating and revising the ratcheted demands as indicated in these rates alleviates an unintented inequity. This change has no effect on BPA's revenue requirement.

Under certain conditions, when a computed demand customer receives more Federal firm power than it is otherwise entitled, this excess amount is called an unauthorized increase or overrun. The priority firm rate schedule contains an unauthorized increase provision that applies to any customer taking non-contractually authorized power from BPA.

Comments were received during the initial proposal hearings on this overrun penalty charge. It was felt that the determination criteria for the unauthorized increase should be applied uniformly and treated as a contract, not as a rate matter. It is very difficult for a customer to buy on a computed demand basis. A computed demand customer, despite its best efforts, might not be able to avoid an overrun because of the variations in load. Recognizing the difficulty, BPA has been negotiating with the computed demand customers over the last 2 1/2 years to develop a set of basic principles that will help alleviate overruns in almost all cases. In the process of negotiating current power sales contracts, BPA is contemplating including these basic principles so they would apply uniformly to all customers.

Parties also questioned the appropriateness of the level of the overrun charge, stating that the charge should be based on the cost to BPA of purchasing power to meet the overrun load. The overrun charge is not a cost-based charge, but rather it is set at a level high enough to discourage BPA's customers from taking an unauthorized amount of power from BPA. Every computed demand customer has scheduling access to the entire interconnected system. If there is power available for purchases, I think the computed demand customer should make the purchase rather than acquiring the power from BPA and thereby incurring an unauthorized increase charge. The overrun charge is set at 130 mills per kilowatthour to encourage the customer to acquire the additional power elsewhere rather than requiring BPA to supply it. Such a charge received the approval of FERC regarding BPA's 1979 wholesale power rates (see Order of November 21, 1980, Docket EF 80-2011, 45 FR 79545, 79548).

b. Alternative Rate Structures

During the development of the PF-1 rate proposal, BPA received many comments on and considered the applicability of several alternative rate designs including inverse elasiticity based rates, tiered rates, and long run incremental cost based rates. Although it would be theoretically possible to design the PF-1 rate schedule incorporating one or more of these rate mechanisms, there are certain difficulties inherent in data collection, making appropriate calculations, determining with relative certainty whether the desired objective would be met, and reaching a prescribed revenue level. These problems are discussed in greater detail in Section III(C)(2) of this decision document, Appendix B. of the Summary Rate Design Study of February 1981, and Section II(B)(1) of the Final Environmental Assessment. As a result of BPA's research and available information in these areas, I have structured the PF-1 rate as described in the previous paragraphs.

2. Wholesale Power Rate Schedule for Industrial Firm and Modified Firm Power, IP-1 and MP-1

a. Description

The IP-1 and MP-1 rate schedules are for sales of Federal power to BPA's direct-service industrial (DSI) customers, and replace schedules IF-2 and MF-2. The loads of these customers 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 other firm customer's loads when the Federal system is unable to meet its firm power commitments as the result of insufficient generation or transmission capacity.

The demand charges are time-differentiated on both a daily and a seasonal basis. The peak seasonal demand charge is in effect from December through May, Monday through Saturday, 7 a.m. to 10 p.m. The secondary seasonal demand charge is in effect from June through November, Monday through Saturday, 7 a.m. to 10 p.m. There is no demand charge for deliveries during offpeak hours (all hours not included in the other two periods). The energy charge is seasonally differentiated based on an analysis of the cost of seasonal hydro storage. The two energy seasonal periods are April through August and September through March. The existing IF-2 and MF-2 rates are time-differentiated in the same manner.

BPA is offering two power rate schedules to DSI customers to allow for billing differences associated with the two types of contracts available to these customers. All DSI customers are currently operating under interim contracts that can be terminated individually by either the customer or by BPA with 30-days notice. If the interim contracts are terminated, conditions for power sales revert to those specified under prior contracts. Because of the significant differences in the quality of power provided to DSI customers between the interim contracts and prior contracts, BPA is offering the MP-1 rate schedule, with its special provisions, for sales made under the prior contracts. Although the IP-1 and MP-1 rate schedules share many common features, significant differences occur in the areas of availability, value of reserves adjustment and advance of energy.

A value of reserves adjustment is included under the IP-1 rate schedule but not under the MP-1 schedule because of the difference in the quality of power available under the two rate schedules and associated contracts. BPA has less right to restrict load under the MP-1 rate schedule than under the IP-1 schedule. Under the IP-1 schedule, BPA can restrict up to one-quarter of the DSI customers' contract demand at any time for any reason. Second quartile restrictions also can be made for delays in completion of construction of hydroelectric and thermal plants. Restrictions also can be made in the event of forced outages and to maintain system stability. These restrictions allow BPA to refrain from developing the resources that otherwise would be required to provide reserves. Under the IP-1 schedule, BPA compensates the industries with a reserve credit adjustment.

b. <u>Value of Reserves</u>

A value of reserves study was performed for the 1981 wholesale power rate filing to determine how to compensate the DSI's for BPA's restriction rights on DSI load and to permit compliance with Section (7)(c)(3) of the Regional Act. BPA's restriction rights on DSI load offer three types of reserves: operating, planning, and stability reserves. Because BPA does not plan resources to serve the DSI top quartile, the top quartile offers only operating and stability reserves. The second and third quartile offer planning, operating, and stability reserves. The fourth quartile offers only stability reserves. In the short run, planning reserves are also operating reserves. Therefore, the definition of operating reserves for this study exclude restriction rights that offer planning reserves so that reserves are not double counted. Consequently, the top quartile was valued as an operating reserve and the second and third quartiles were valued as planning reserves. The value of stability reserves was based on an alternative load tripping scheme.

Since the top quartile was served only with nonfirm energy in the past, it was not considered as providing a reserve. In order for a restriction right to offer a reserve, there naturally must be a load present to be restricted. There is some merit to the idea that the top quartile offers a reserve between average and critical streamflows. However, since BPA operates to meet its loads under critical water conditions, the value of this reserve is questionable.

Under the Regional Act BPA is obligated to operate the Federal system to serve the top quartile as if it were firm load. Therefore, I believe service to the top quartile is "quasi-firm" and consider the top quartile load a quasi-firm load. In the value of reserves study for the initial proposal it was assumed that BPA would shape Firm Energy Load Carrying Capability (FELCC) from a later year in the critical period into the first year of the critical period in order to serve the top quartile. Hence, the top quartile would be essentially firm for that 1 year and would offer an operating reserve. This assumption has been modified for the final proposal. It is now assumed that BPA will shape FELCC in order to serve the top quartile for only 6 months of the operating year. For the other 6 months, the top quartile is proposed to be served with generation resulting from better than critical streamflow conditions.

For the initial proposal an analysis was undertaken to determine how much of the top quartile would be exposed to operating restrictions in FY 82. These megawatthours were then valued at BPA's average purchase power costs. A similar analysis was conducted for this final proposal, but because of the modified assumption, only the first 6 months of exposure in operating year (OY) 82 were valued at BPA's average purchase power cost of 45 mills per kilowatthour. Since for the first 6 months of OY 82, BPA will serve the DSI top quartile with shifted FELCC, it, in effect, is firm. Therefore, BPA would be willing to purchase power to meet this load, if necessary.

BPA's alternative to operating reserves provided by the DSI load is to purchase power on a short term basis to provide the reserves. For the last 6 months of OY 82 BPA will not purchase power to meet the top quartile load. Thus, the value of the operating reserves is difficult to quantify for the remaining period. The average nonfirm rate takes into account the reserve benefits of nonfirm energy. In recognition of the fact that the remaining portion of the top quartile is served with what otherwise would be nonfirm energy, service to this portion of the top quartile, for the last 6 months was priced at the average nonfirm energy rate when calculating the DSI rate.

The DSI's expressed the concern in the rate hearings that the value of reserves in the Modified Firm contracts had not been calculated. In reviewing these contracts, restriction rights are only associated with the top quartile and are the result of its being served with nonfirm energy and is not quasi-firm. As stated earlier, prior to passage of the Regional Act, the top quartile was not considered to offer a reserve because it was served by nonfirm energy. Therefore, the value of reserves for the Modified Firm contracts was zero.

The second quartile is restrictable for plant delays, offering an energy planning reserve, and for forced outages not to exceed

375 times the IF contract demand, offering a capacity planning reserve. The third quartile is restrictable for forced outages for up to 2 hours a day, but not to exceed 50 times the IF contract, offering a capacity planning reserve. Since BPA's planning reserve requirements are reduced by the amount of the second and third quartile restriction rights, the amount of energy planning reserves is equal to the amount of the second quartile. Likewise, the amount of the capacity planning reserves is equal to amount of the second and third quartiles.

Unlike the top quartile, the probability of using the second and third quartiles is not an appropriate measure of the reserves or their value. The restriction rights, not the actual restrictions, are valuable. The same holds true for utility systems that must maintain standby generation capacity for reserves. The cost must be recovered whether actually used or not. The probability of needing the reserves is the primary basis for determining the amount of reserves to carry, not their cost or value. The difference between the top quartile and the second and third quartiles is that BPA does not plan resources to meet the top quartile, but does for the second and third. Therefore, since service to the top quartile is not guaranteed, the restriction rights are not always usable and it must be determined how often they are usable.

For BPA, as for other utility systems, the alternative to these load restriction rights for providing reserves is building standby generation, which can only come from newly acquired generation. Since the DSI contracts are being renegotiated and the decision to build plants or include restriction rights is being made again, the value of the restriction rights is the current cost of additional generation as reflected in BPA's LRIC Analysis. If the reserve was provided by a generation resource, operating costs would not be incurred if the resource was idle. Therefore, the operating costs in the LRIC have not been included in valuing reserves. This results in a capacity planning reserve value of $98 million and an energy planning reserve value of $422 million.

A major concern of the parties in the rate filing was crediting the DSI's for the second quartile energy reserve while at the same time purchasing power to serve the second quartile. There is no inconsistency because BPA must at this time purchase power in order to be in load/resource balance. This includes purchases for the second quartile since it is a firm load. On top of the requirement to have sufficient generation to serve firm loads is BPA's reserve requirement. In effect, the right to restrict a firm load is the only way to achieve firm reserves and is consistent with the alternative of meeting the firm load by acquiring standby generation. However, as pointed out by the parties, in the initial proposal there was some double counting in that both the operating costs for second quartile purchase power and the operating costs associated with the second quartile planning reserves were included. By excluding the operating costs associated with the second quartile reserve, this problem has been eliminated.

Another suggestion from the InterCompany Pool and the Oregon Public Utility Commission was to credit the value with the amount of additional revenues BPA could accrue from selling an idle generation resource as secondary energy. BPA staff has been looking at alternative methods for performing this type of analysis. However, a workable methodology that could be applied consistent with the NF-1 rate and revenue estimates was not provided and it was not possible to conduct the analysis in the time allotted for development of the final proposal. The idea does have merit and work is continuing for future rate filings.

BPA at this time has not developed a satisfactory method for valuing stability reserves and the parties to the rate hearings were unable to suggest adequate alternatives. As a proxy for the value of stability reserves the costs of the alternative to the Import Contingency Load Tripping (ICLT) scheme was used. The ICLT scheme senses the loss of key generating plants or major interregional transmission lines and immediately drops or disconnects 3294 megawatts of DSI load by remote control. An alternative to the ICLT is using non-DSI loads under a similar dropping scheme. The cost of this alternative is $2.4 million, including additional overhead costs that were not included in the initial proposal. Annualizing this investment cost produces a value of stability reserves in FY 82 of $.3 million.

The total value of the three kinds of reserves being provided is $521 million. As explained in Section IX(B)(4), this value was reduced to average costs to arrive at a value of reserves credit of $62 million for energy and $14 million for capacity. A rate adjustment is used to credit the DSI's in recognition of the value of restriction rights to the Administrator rather than the actual use of the restriction rights. An availability credit, contained in existing rates and suggested by some of the parties to the rate hearings, has significant over or under crediting problems. Therefore, a uniform value of reserves rate adjustment of $0.33 per kilowattmonth and 2.3 mills per kilowatthour is included in the IP-1 rate schedule. Since there are no reserves offered by the Modified Firm contracts, the MP-1 rate schedule has no rate adjustment of this type.

c. Rate Change on October 1, 1981

Part of the resources serving the DSI load have been identified as the exchange resources. At this time the average system cost methodology that determines the cost of these resources has not been developed because of the requirement to consult with various interests, to develop rules and to submit the methodology to FERC. Therefore, the DSI rate contains an "X" representing the costs of the exchange resources. The exchange will not take place until October 1, 1981, at the earliest. Consequently, there is a base rate in the IP-1 energy rate based on Federal base system resources, that will be effective from July 1, 1981. When the exchange commences, the greater of the base rate or a rate based on the monthly exchange costs and a projected average monthly total DSI billing energy, will apply as shown in Table 22 WPRDS. The exchange rate is designed such that if all of the eventual parties to the exchange do not sign contracts at the same time, the rate will compensate by increasing as exchange obligations are added.

3. Wholesale Firm Capacity Rate Schedule, CF-1

a. Description

BPA's current F-7 capacity rate schedule is for the sale of peaking capacity. This schedule separately identifies rates for: (a) annual capacity (delivery of capacity throughout the year as requested by the customer) and (b) seasonal capacity (capacity delivered during 5 summer months, principally to Pacific Southwest utilities).

The CF-1 rate schedule supersedes the F-7 rate schedule. The CF-1 rate schedule applies to capacity sales to utilities on both a contract year and seasonal basis. Energy associated with the delivery of capacity is returned to BPA. The contract year rate is derived by accumulating the monthly demand charges for firm power (i.e., under the PF-1 rate) over 12 consecutive months. The rate for contract season service (June 1 through October 31) is derived by applying a 20.9 percent inflation escalator to the summer season capacity rate identified in the existing F-7 rate schedule.

b. Sustained Peaking Change Issue

To encourage capacity purchasers to limit their usage of Federal generating facilities and maximize use of their own facilities, the capacity rate includes an additional monthly charge for capacity usage in excess of 9 hours per day. The reason for this additional charge is that the Federal hydro system cannot generate as much capacity during sustained daily periods (i.e., in excess of 9 consecutive hours) as it can for shorter periods (i.e., less than 9 hours). When the FCRPS generates capacity for extended periods, the ability of the FCRPS to meet firm commitments is reduced. Moreover, return of significant amounts of energy during offpeak hours may induce the Federal system to sell the returned energy, thus reducing firm energy capability, or to spill water. The potential for environmental impacts related to river fluctuation and nitrogen supersaturation may be reduced if capacity purchasers limit their usage of Federal generating facilities.

Previously, and in BPA's initial proposal, the development of this additional charge for sustained peaking was based on an alternative cost principle applied to an estimate of the fuel savings realized by the customer not having to operate a combustion turbine peaking plant. This methodology was criticized by customers and individuals who felt this type of sustained peaking charge was neither equitable nor cost based.

BPA incurs costs directly in relation to the length of the daily sustained peak period and these costs should be recovered through an appropriate rate mechanism. I feel that BPA's F-7 variable share-the-savings technique (halving the difference between baseload unit and peaking unit power costs) is a viable ratemaking alternative. However, in the current proposal I have opted to base the charge on estimated incurred costs. That is, the CF-1 customer class' estimated contribution to the reduction of the FCRPS sustained peaking ability will be added to the monthly capacity charge based on each hour or fraction thereof, in a given month in which the customer exceeds 9 hours of demand duration per day. The added charge is $0.029 per kilowattmonth for each additional hour or fraction thereof, of capacity in excess of 9 hours. This charge was calculated by determining the reduction in Federal system sustained peaking capability as demand duration goes from 9 hours (average public agency demand duration) to 15 hours. This reduction is then applied pro rata to all capacity customers with CF-1 assigned its proportionate share. The reduced capability is valued at the average Federal base system capacity rate.

The cost of capacity purchases in excess of 9 hours under the CF-1 rate exceeds the cost under the PF-1 rate because the service provided is different. The CF-1 rate provides a load-shaping service by allowing for the return of energy during offpeak hours. Raising the cost of this service by lowering the maximum number of hours that capacity purchases can be made without an additional charge does not constitute a unilateral change in the nature of the commodity sold. Rather it reflects the fact that the sustained peaking capability of the Federal hydro system is reduced if the time period over which peaking capability must be maintained is increased. The proposed hours reflect that constraint. The additional monthly charge for capacity usage in excess of 9 hours per day is to encourage capacity purchasers to limit their usage of Federal generating facilities and to compensate BPA for the estimated reduced capabilities of the FCRPS.

4. Wholesale Emergency Capacity Rate Schedule, CE-1

The CE-1 rate covers emergency capacity provided to utilities on a weekly basis, when available, and the return of energy associated with the delivery of this capacity. BPA will provide short-term capacity sales only when an emergency condition exists as defined by BPA's General Contract Provisions (Section 16 "Uncontrollable Forces") and when BPA has capacity available. The CF-1 contract year rate per kilowatt 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 $0.56 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 $0.22 per kilowattweek. This charge was derived by dividing the intertie costs allocated to CF-1 seasonal capacity in the COSA by the billing determinant for CF-1 seasonal capacity.

5. New Resources Firm Power Rate Schedule, NR-1

The NR-1 rate is available for the purchase of firm power for resale or for direct consumption by purchasers other than DSI customers. It can be used by investor-owned utilities to purchase power to serve their previous year's deficit plus any load growth for the current year and public bodies or cooperatives to purchase power to serve their new large single loads.

Section 7(f) of the Regional Act requires the establishment of the rate. It is based only on the costs of the New Resources pool. Federal base system resources and exchange resources are serving the loads provided for under Sections 7(b) and 7(c) of the Regional Act, and therefore are not available to serve NR-1 loads.

This rate has been time differentiated in the same manner as the priority firm rate. The demand charge is also set equal to the demand charge for the PF-1 rate schedule. This adjustment represents an increase in costs classified to capacity and allocated to the rate. The energy charge was decreased to compensate for the increase in the demand charge.

6. Wholesale Nonfirm Energy Rate Schedule, NF-1

a. Rate

The NF-1 nonfirm energy rate is based on the cost of resources that contribute to the availability of nonfirm energy. The rate charged under the NF-1 rate schedule is based upon: (1) the diurnally differentiated cost of Federal hydroelectric power, at 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m., and 3.0 mills per kilowatthour for all other hours of the year; (2) the cost of power purchases; (3) the cost of other resources that have been operated; or (4) a weighted average of costs from the preceding categories. A charge of 2.0 mills per kilowatthour, the average cost of transmission for energy from Federal base system resources, is added to the kilowatthour charge for each sale of nonfirm energy. The floor rates, which are equal to the diurnally-differentiated cost of Federal hydroelectric power plus the 2.0 mills per kilowatthour transmission charge, are 5.0 mills per kilowatthour during offpeak hours and 6.5 mills per kilowatthour during peak hours. The ceiling rate at any time is equivalent to the cost of the most expensive power purchase or resource operated since the preceding July 31 or since the last time that all FCRPS reservoirs were substantially full. This is also limited to the amount of power resulting from that particular purchase or resource. For contracts that refer to this rate schedule for determining the value of energy, the rate is 9.6 mills per kilowatthour which is the average NF-1 sales rate.

The costs from categories 1-3 above may be combined to derive an average charge. As an amount of energy associated with any given power purchase or resource is used to derive a charge for a sale of nonfirm energy, that purchase or resource cost will no longer be used to determine the rate for subsequent sales of nonfirm energy. Furthermore, the resources and costs associated with categories 2 and 3 above (power purchased or resources other than hydro) are included, only to the extent they either (1) are providing power to BPA concurrently with the nonfirm sale or, (2) they can be shown to have operated or have been purchased and are still in the reservoir system. In other words, the reservoirs have more water in them which makes our sale of nonfirm possible by virtue of operating or purchasing the other power and not generating at that time with hydro. This concept is critical to not only reflect our actual operating characteristics but to assure that we don't take undue risk and not operate or purchase these other resources because we wouldn't have a chance to recover the costs. In the end, our nonfirm marketing strategy, both rates and sales policy, must assume that the most expensive depletable fueled resource within our interconnected area is displaced.

The variability of market and water conditions cause me to believe that a flexible rate structure of this kind is most appropriate for marketing BPA's nonfirm energy to best achieve the objectives. A fixed rate structure that is set too low could not offer justification for operating thermal generation, either directly or through purchases, in order to make nonfirm energy available to displace the appropriate resources. A fixed rate that is set too high would at times preclude BPA from selling available nonfirm energy, thus forcing BPA to spill water and waste energy and valuable resources elsewhere. A high fixed rate would also not provide the operators of other Northwest resources with an economic incentive to use nonfirm energy from BPA to allow them to continue to operate their low cost thermal, and thus economically displace relatively higher cost oil-fired thermal. In effect, the fixed rate concept, either high or low, distorts the economics, ignores the then current operating characteristics, and fails to achieve one of the important purposes of marketing nonfirm. The adopted variable rate structure will assure BPA of maximum flexibility to respond to market conditions so that the resources that should be displaced, whether in the Pacific Northwest or in the Pacific Southwest, will in fact be displaced. It is a necessary conclusion on both a national and regional basis.

The NF-1 rate is designed to reflect the costs of resources used to produce nonfirm energy. BPA determines the availability of energy to meet firm loads on the basis of critical water conditions. To protect the capability of the FCRPS to meet firm load obligations in any given operating year, BPA operates resources other than hydro and may make relatively expensive power purchases during the fall and early winter of the year. Subsequently, if snowpack and streamflows prove to be greater than anticipated in late winter and spring, more energy can be produced than is necessary to meet firm loads of all types, and nonfirm energy becomes available. Thus, the NF-1 nonfirm energy rate is based on the costs of power from hydroelectric facilities, power purchases, and other resources. All of these resources aid in maintaining BPA's capability to meet firm load obligations under critical water, but contribute to excess requirements with the occurrence of greater than critical streamflows.

b. Cost of Service

Although Southwest parties testified that the NF-1 rate should be based on cost of service, I believe the NF-1 rate is based on BPA's costs and that the flexible rate structure based on other resource and purchased power costs that contribute to the availability of nonfirm energy is most appropriate.

Any rate based on the results of the COSA allocation process or the variable production cost of hydroelectric power would be unreasonably low. The COSA allocates only intertie costs to nonfirm service because development of generation resources is designed to meet firm loads under critical water conditions. As indicated in the hearings, the variable production cost of hydroelectric power is generally less than 1 mill per kilowatthour. If the nonfirm rate were based on these costs, benefits from sales of nonfirm would be distributed inequitably because the Southwest would receive a greater portion of the benefits than the Northwest. Section 5 of the Northwest Regional Preference Act, 16 U.S.C. 837d, Pub. L. 88-552, provides, with regard to the sharing of benefits:

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

In addition to benefitting from the Northwest integrated generation and transmission system which was built at a great financial and environmental cost to the region, the Southwest would realize a savings of 40 to 50 mills for every kilowatthour of nonfirm energy that they purchase. Thermal plants are often operated concurrently with sales of secondary energy to provide energy for secondary sales. A low rate based on the above costs would not cover the thermal operating costs and thus, would not justify the continued operation of the thermal plants. This would be detrimental to nonfirm energy purchasers, assuming that they would be willing to pay a rate sufficient to justify continued plant operation.

Other comments were received on various aspects of the cost-of-service issue. The first of these comments states that the NF-1 rate is inappropriate because BPA is marketing dump energy. However, it is clear to me that the nonfirm energy sold under the NF-1 rate is not always dump energy. During the summer months, particularly May and June, BPA will be in a situation where water will be spilled if nonfirm energy sales are not negotiated. In such situations, BPA anticipates that the charge will be at the floor rates for all nonfirm sales. However, during the remainder of the year, BPA will be making purchases and operating thermal. If energy is being stored above the energy content curves, NF-1 sales may be made concurrently or at a later date. In these cases, operation of thermal resources and power purchases contribute directly to the availability of nonfirm energy.

Another issue raised is that Saturday should not be included as a peak day nor should the power cost from hydroelectric facilities be diurnally differentiated to be in accordance with the results of the TDPA. After studying the results of the TDPA, I have based my decision to retain Saturday as a peak day on reasons of rate continuity and other considerations (Section IX(B)(1)). I also find it proper to diurnally differentiate the cost of power from hydroelectric facilities. This portion of the rate is based on energy and capacity costs of hydro, and hydro capacity costs are diurnally differentiated in the TDPA.

It has been suggested that BPA is required to base its rates for each general class of service on the costs of providing that service. However, a review of the cost language contained in the pertinent statutes clearly rejects this suggestion. Section 7 of the Bonneville Project Act, 16 U.S.C. 832, provides that:

"Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of 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. Rate schedules shall be based upon an allocation of costs made by the Federal Power Commission. 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." 16 U.S.C. 832f.

The "allocation of costs" by the Federal Power Commission between power and "other purposes" refers to the need to determine what portion of the construction cost of the Federal multipurpose dams is to be repaid from power revenues, as being power-related costs of construction, and which construction costs are to be allocated to navigation, recreation, and irrigation. This "allocation of costs" language does not support the parties' assertions nor does the legislative history.

The legislative history of the Bonneville Project Act demonstrates the concern by Congress that the Federal debt be repaid but does not mention any particular rate design to be used to recover the debt. A major address delivered on the proposed legislation by Congressman Pierce of Oregon, a leading advocate of the bill, states:

> "It has long been a congressional policy <u>not to express an exact or fixed formula in any bill</u>, but to control and check by regulation. There are two reasons for this, first the question as to constitutionality, and secondly, considerations vary with time, distance, area, growth, and economic conditions. This congressional policy has long existed in railroad rate regulation. <u>An exact legislative fixed formula would not provide the requisite flexibility for growth and progress</u>." Columbia River (Bonneville Dam) Oregon and Washington. Hearings on H.R. 7642. Before the House Comm. on Rivers and Harbors 75th Cong., 1st Sess., 181 (1937).

In fact, it becomes apparent from a reading of the legislative history of the Bonneville Project Act that one of its primary objectives would not have been met if cost-based rates were required. An objective of the bill was to encourage the most widespread use of electric power in the region. A widely debated issue was whether a uniform rate, not based on cost, would encourage widespread use more than a zone rate, that is lowest at the dam, increases with distance and reflects actual costs. The concern was that customers located farthest from the dams would not be able to pay actual costs using zone rates and the objective of widespread use would not be attained.

In addition, the language of Section 9 of the Federal Columbia River Transmission System Act, 16 U.S.C. 838 (Transmission System Act), provides that rates:

> "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 <u>to the recovery</u> (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 . . " (emphasis added)

The House Report on the Transmission System Act provides the following in its analysis of Section 9:

> "Rates and Charges. -- This section consists of a restatement of statutory standards and principles for derivation of wholesale rates for sale of power by the Bonneville Power Administration and an application of the same standards and principles to the derivation of charges for wheeling non-Federal power." H.R. Rep No. 1375, 93d Cong. 2d Sess. 5 (1974).

Since it is merely a restatement of the standards found in the Bonneville Project Act, Section 9 of the Transmission System Act provides no new law to apply with respect to the rates charged for power sold by the Bonneville Power Administration.

Both the language of Section 7(a)(1) of the Regional Act, the rate directives section, and the legislative history clearly indicate that Section 7(a)(1) is a restatement of the standards set forth in the Bonneville Project Act and the Transmission System Act. The Senate Report on the Regional Act notes:

> "Section 7(a).--This section restates the Administrator's obligation periodically to establish and modify electric power and transmission rates. These rates shall continue to be established at levels to recover revenues sufficient to pay all of the Administrator's costs." S. Rep. No. 272, 96th Cong. 1st Sess. 31 (1979) (Emphasis added).

The House Interior Report similarly notes:

> "Section 7(a) continues the requirement of existing law that BPA set its rates to recover, in total, the full cost (but not more than the full cost) of its financial obligations." H. Rep. No. 976, 96th Cong. 2d Sess. 52 (1980) (Emphasis added).

Thus, BPA is directed to set rates that are as low as possible consistent with sound business principles as long as they are cumulatively high enough to repay all appropriate costs. The language in the three statutes discussed does not impose a cost-of-service requirement, but relates only to the revenue requirement. Additionally, rules of statutory construction support this view that it would be improper to imply a cost-of-service standard when this requirement is not explicitly set forth in the statutes.

The contention that Section 7 of the Bonneville Project Act imposes a cost-of-service standard on BPA was rejected in Pacific Power and Light v. Duncan, 499 F. Supp. 672 (D. Or. 1980), appeal dismissed, No. 80-3517 (9th Circ., Feb. 13, 1981). The court noted, with reference to Section 7 of the Bonneville Project Act and BPA's PURPA 111 Order, 44 Fed. Reg. 68948 (1979), discussed infra:

> "Despite all the references to cost, the two quoted passages do not support an inference that cost is the only basis upon which rates may be computed. The qualifying phrases 'having regard to,' 'may include,' and 'to the maximum extent practicable,' indicate that the discretion granted in 16 U.S.C. §§ 825s, 832e, 838g; and 43 U.S.C. § 485h(c) were not significantly altered by the requirement to consider costs in calculating rates. See City of Santa Clara." Pacific, supra, 499 F.Supp at 683.

The court continued to note that "[T]he statutory schemes, taken as a whole, invest the Secretary with such broad discretion, that with respect to the ratemaking challenged here, judicial review is not available because there is no law to apply." Id. at 683.

This conclusion was further upheld in The Montana Power Company and Idaho Power Company v. Edwards et al., Civil No. 80-842 PA (D. Or. May 18, 1981) (not yet reported), where the court noted:

> "Although plaintiffs did not directly challenge the rate design, they impliedly did so when asserting a breach of contract. I note that the particular rates challenged here are not susceptible to judicial review because there is no law to apply. PP&L, at 681-683," Id. at 7 (citations omitted).

Rates based on considerations other than cost of service have met with administrative approval. Three other power marketing administrations, Southeastern, Southwestern, and Western Area Power Administrations, have received approval of share-the-savings rates. This rate structure has also been commonly used by IOU's including Pacific Power and Light and Montana Power Company. It is also common utility practice to base nonfirm energy rates on the recovery of incremental costs plus up to 100 percent of fixed costs. The utilities mentioned above as well as Idaho Power Company and Puget Sound Power and Light Company use this sort of pricing for certain nonfirm energy sales.

One witness for the California municipal parties argued that although his utility charges rates for nonfirm in excess of incremental cost (Transcript, p. 3623), a distinction can be drawn between nonfirm energy contract rates and rate schedules. I find the distinction to be one without distinction to be one without a difference. In order to make a sale under the NF-1 rate schedule, the customer must be offered the power and must accept the offer at a determined price. Although a verbal contract between power schedulers, I find no difference in kind between such a verbal contract and a written contract for sale of power which allows charging rates for nonfirm power in excess of incremental costs.

In departing from a strict cost-of-service methodology for the NF-1 rate, BPA is conforming properly with the cost of service determination of Section III 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 the Pacific Power & Light Company case, as noted earlier, 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. That is all the PURPA requires." Id. at 683 (emphasis in original).

c. Rate Objectives

Another area of concern to the parties was whether the NF-1 rate schedule complied with BPA's stated rate objectives and considerations (Summary Rate Design Study, p. 10). The first of the assertions in regard to the objectives was that a poor water year may jeopardize BPA's ability to meet its annual repayment requirement because the amount of revenue from NF-1 sales is dependent upon water conditions. Furthermore, if NF-1 were based on cost of service, BPA would not be exposing itself to the same degree of revenue instability and would be able to meet the repayment obligation.

These parties apparently do not have a full understanding of BPA's repayment process. BPA's repayment obligation is based on a study that uses a period of 50 years to repay the investment in hydroelectric projects and 35 years for investment in transmission facilities. The repayment study analyzes how BPA may meet its obligations during a period in excess of 50 years. BPA's ability to repay the investment would not be jeopardized by a failure to collect a forecasted amount of revenues in any 1 year. Thus, a poor water year with lowered NF-1 sales and revenues would not endanger BPA's ability to meet its repayment obligations. Revenue instability results primarily from water conditions rather than from the amount of revenue BPA forecasts to be collected from its nonfirm energy sales. Regardless of the rate structure, water conditions dictate the level of nonfirm sales possible.

Another issue regarding the rate objectives is the contention that NF-1 customers, particularly Southwest customers, are subsidizing firm power customers by paying the costs of purchased power and thermal generation that are incurred for firm power service. However, I believe that the objective of equity is served by the NF-1 rate. The NF-1 rate is based on the costs of resources that contribute to the availability of nonfirm energy and implicitly recognizes the value of the generation and transmission systems of the Pacific Northwest from which nonfirm customers receive an enormous benefit. The sharing of this economic benefit is referred to in Section II of this Record of Decision. BPA's sharing of benefits was in response to a General Accounting Office report. In a letter from John P. Carroll, Regional Manager, U.S. General Accounting Office, to the Administrator, dated September 11, 1976, the question of an appropriate BPA nonfirm energy rate was addressed. The General Accounting Office report which accompanies the letter states that:

> "The current Bonneville rate for secondary energy may be inconsistent with sound business principles and with the concept of equitable sharing of benefits because it does not fully reflect the value of the energy it displaces."

In addition, all nonfirm energy customers, Northwest as well as Southwest, are subject to the same NF-1 rate schedule and pay the same costs and also receive the benefits. Southwest customers also benefit from the reduction in the CF-1 firm capacity rate due to the crediting of excess nonfirm energy revenues to firm capacity costs.

A concern was raised that the imposition of the streamflow conditions adjustment would result in purchased power costs being collected twice. Since I have determined that the adjustment will not be included in the rate schedules for this rate filing, it is not necessary to discuss this issue further.

A fifth area of concern was that the NF-1 rate will have a negative effect on conservation by not reflecting the true costs of firm energy. It is believed that because nonfirm energy is priced above its cost and firm power rates are correspondingly lower, consumption by firm power customers is encouraged. Currently, however, there is insufficient information available with regard to the relative elasticity of demand of Northwest customers versus Southwest customers to conclude that the crediting of nonfirm energy revenue to firm capacity costs instead of other costs would result in a net total increase in consumption. At this time the need to displace certain resources to save needed fuels is a greater objective and overrides this concern.

Another concern is that BPA's nonfirm energy rate will not always be the lowest cost alternative available to utilities, and thus, nonfirm energy will be spilled rather than be used to displace higher cost resources. I do not contemplate a situation occurring when water would be spilled because of the price of nonfirm energy. A great deal of flexibility has been incorporated in the NF-1 rate to respond to water and market conditions to meet this and other similar concerns. In addition, it is BPA's policy to avoid spill situations. When necessary, BPA will sell at the floor rates, 6.5 mills/kWh during peak hours and 5.0 mills/kWh during all other hours, until the secondary market is saturated in order to minimize spill. The Southwest operates high-cost oil-fired thermal at an incremental cost of over 40 mills, and thus, it seems unlikely that the Southwest would not be willing to buy any available low-cost energy.

The final comments regarding the rate objectives dealt with rate continuity, ease of administration and ease of understanding. Although it is true that the proposed NF-1 rate has a different structure than the present H-6 nonfirm energy rate, it does not appear that this would disturb the California parties who have objected vigorously to the H-6 rate. In fact, some of the administrative problems of H-6 have been eased with the NF-1 rate. Under the NF-1 rate voluminous records would not have to be kept nor would utilities have to supply information to BPA on a daily basis. I do not believe that the rate is difficult to understand and although BPA retains a great deal of flexibility in administering the rate, the administration of the rate has been well detailed during the rate development process. In addition, the rate addresses the principal objections raised by the California parties relative to the H-6 rate.

d. Marketing Policy

Parties have been concerned about the NF-1 marketing policy. Although it is not a rate matter, the marketing policy was described by staff during the rate hearing process and I shall reiterate this policy here.

The marketing policy will fundamentally remain the same under the new NF-1 rate. The methods of implementing the policy will necessarily change to conform to the difference of the rate but also to implement the policy under different operating and marketing conditions. The following is a list of the objectives and considerations that make up our nonfirm marketing policy and will be used to direct the implementation. All objectives must be viewed together with no single objective receiving special emphasis. These objectives are derived either directly or indirectly from the statutes applicable to BPA.

(1) Encourage widespread use.

(2) Comply with Pub. L. 88-552.

(3) Assure that benefits from NF-1 sales accrue to all ratepayers in the region and not just to ratepayers directly affected by BPA rates to its customers. The rate assures the benefits will be appropriately shared with those outside the region.

(4) Consideration of existing market conditions.

(5) Fish and wildlife considerations.

(6) Consideration of the customer's use of the nonfirm energy.

(7) Encouragement of conservation and renewable resource development.

(8) Conformity to National Energy Policy.

The maximization of revenues has not been nor is it an objective of BPA's nonfirm energy marketing policy. Thus, BPA will continue its present policy in marketing nonfirm energy under the NF-1 rate. It should be noted that our policy is neither prescriptive nor a specific formula. All formulas considered (either suggested to or developed by BPA) do not adequatly meet the stated policy.

There were considerable questions about the meaning of objective number (3). In essence, an attempt will be made to balance the benefits accruing to BPA from sales of our nonfirm energy with the benefits accruing to non-BPA utilities in the region through the displacement of the other utilities' own generation or purchase contracts including resale, if any, of the displaced power.

e. <u>Transmission Charges</u>

The appropriateness of the transmission charge has been questioned, particularly that this component of the NF-1 rate should be reduced or deleted. The arguments raised in favor of a change are: (1) the BPA transmission system is designed to meet peak demands of firm customers, (2) NF-1 customers enjoy no capacity rights on BPA's system, (3) there is no significant incremental transmission cost associated with surplus sales, (4) BPA is proposing to recover the same transmission costs twice, (5) BPA is exposing itself to problems of revenue stability by charging a large transmission component, (6) the capacity/energy exchange agreements were not considered in formulating the transmission charge, and (7) intertie costs should not be allocated to nonfirm energy service.

I believe that the NF-1 transmission component explicitly recognizes the benefits of the Northwest integrated transmission system to nonfirm purchasers by charging the average cost of Federal base system energy transmission. In addition, recognition of a specific charge facilitates the process of crediting nonfirm revenues to allocated transmission costs in the rate design process.

The capacity/energy exchange agreements were not considered in formulating the NF-1 transmission component, but I do not consider these contract agreements to be germane to discussions of the NF-1 rate. If capacity/energy exchange customers are given the option of not returning the energy, they pay 3 mills per kilowatthour as per the contract agreement. Transactions under the Exchange Agreement are separate from transactions under the NF-1 rate. Citations to the Exchange Agreement (Contract No. 14-03-50323), while noting that consideration of transmission factors is appropriate for transactions under such agreements, fail to specify that the consideration of such factors is intended to encompass costs for all transactions related to the intertie of any nature whatsoever. Such a suggestion is contrary to the plain meaning of the Exchange Agreement, which discusses costs solely in reference to those necessarily associated with transactions undertaken thereunder. Such an agrument is also contrary to legislative history of Pub. L. 88-552 which expressly notes secondary sales as a primary purpose for construction of the intertie, discussed below.

BPA is not recovering transmission costs twice since the nonfirm revenues are credited to transmission costs and netted out before the transmission charges for other service classes are calculated. In addition, as noted above, BPA's nonfirm rates need not be cost based. The issue of revenue stability has been addressed earlier in Section c. in regard to rate objectives.

It has been suggested that transmission capacity costs should not be allocated to nonfirm energy service in light of a FERC decision, Kentucky Utilities Co., Opinion No. 116, Docket No. ER 78-147, issued April 2, 1981. FERC ruled that customers subject to curtailment of delivery or interruption by the utility should not be allocated transmission capacity costs. This FERC decision was not applicable to BPA's NF-1 service over the intertie. FERC's decision is based on the fact that no evidence was in the record to show that the customer had caused the utility to build any transmission facilities. BPA allocates intertie costs to nonfirm service because the intertie was built, in part, to provide for nonfirm energy transmission. Appropriations for construction of the intertie were conditioned upon the enactment of legislation recognizing a regional preference for Pacific Northwest electric consumers regarding energy generated at Federal hydro facilities in that region and, in addition, a determination of the economic viability of the intertie. This was provided in the Conference Committee Report accompanying H.R. 9140, H. Rep. No. 1027, 88 Cong. 2d Sess 24 (1963) which adopted the language of S. Rep. No. 746, 88 Cong. 2d Sess. 39-40 (1963). The legislation that was enacted and provided for these concerns was S. 1007 on Pub. L. 88-552, the Regional Preference Act. The legislative history of Pub. L. 88-552 is replete with references recognizing secondary sales as a primary purpose for construction of the intertie. E.g. S. Rep. No. 122, 88th Cong. 1st Sess. 3 (1963). BPA's allocation of intertie costs to nonfirm service is thus clearly distinguishable from Kentucky, supra.

f. Alternatives

All recommendations for alternative nonfirm energy rates were based on a fixed rate structure. I believe that the flexible rate is most appropriate for reasons discussed in Section a. The alternative rates were represented to be fair, equitable, and to prevent discrimination. However, it appears that benefits derived from a fixed rate would not satisfy our objectives.

Forecasting and planning by BPA's customers would not be appreciably improved by these alternatives as has been claimed since the greatest degreee of uncertainty results from variable water conditions and not rate level or structure. The problems of revenue stability do not affect BPA's ability to meet its repayment obligations (Section c). The floor rates appear to be low enough so that BPA will not lose sales because of a high price. In addition, capacity costs are not collected twice when capacity/energy exchange customers pay for the energy instead of returning it to BPA. If capacity/energy customers are given the option of not returning the energy, they pay 3.0 mills per kilowatthour consistent with the contract agreement.

Finally, the construction of a third intertie would not be delayed unduly by the NF-1 rate structure. According to a General Accounting Office report, "Oil Savings from Greater Intertie Capacity Between the Pacific Northwest and California," the nonfirm energy rate is one of many factors that must be considered when planning a third intertie. Other major factors include the projected Northwest energy deficit, expected sales from Canada, oil prices, the amount of surplus energy available, California private utilities' access to BPA power versus the California public utilities, and the ability to obtain Congressional approval to construct another intertie.

7. Reserve Power Rate Schedule, RP-1

The RP-1 rate schedule replaces the EC-9 rate schedule. The Reserve Power Rate Schedule is applicable 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 be applicable.

This rate schedule is derived directly from the results of the LRIC Analysis and the TDPA. The demand charges reflect the incremental costs of capacity and transmission facilities based on the costs of hydroelectric peaking facilities and transmission facilities. The energy charge reflects the incremental cost of energy based on the cost of baseload thermal with an adjustment for a capacity credit. The generation capacity component of each demand charge is time differentiated while the transmission component is not. Thus, the winter demand charge includes incremental costs of both generation capacity and transmission, and the summer demand charge includes only incremental costs of transmission. The energy charge is not time differentiated. An adjustment for power factor is included.

8. Wholesale Firm Energy Rate Schedule, FE-1

The FE-1 rate schedule replaces the J-2 rate schedule. This rate is designed to provide firm energy to contract purchasers in the amounts and during the periods specified in their contracts. The rate is based on the PF-1 rates, 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 it is determined that BPA is unable to provide delivery because of system operating conditions.

9. Special Industrial Power Rate Schedule, SI-1

During the hearings the Hanna Nickel Smelting Company (Hanna) requested a special power rate pursuant to the provisions of Section 7(d)(2) and Section 7(c)(3) of the Regional Act.

Section 7(d)(2) allows the Administrator to establish a special rate that need not be cost-based, if any direct-service industrial customer using raw materials indigenous to the region will suffer adverse impacts of increased rates pursuant to the Regional Act, and if all power sold to such a customer may be interrupted or withdrawn to meet firm loads in the region. Section 7(d)(2) states as follows:

> "In order to avoid adverse impacts of increased rates pursuant to this Act on any direct service industrial customer using raw minerals indigenous to the region as its primary resource, the Administrator, upon request of such customer showing such impacts and after considering the effect of such request on his other obligations under this Act, is authorized, if the Administrator determines that such impacts will be significant, to establish a special rate applicable to such customer if all power sold to such customer may be interrrupted, curtailed, or withdrawn to meet firm loads in the region. Such rate shall be established in accordance with this section and shall include such terms and conditions as the Administrator deems appropriate."

Also, as background to Section 7(d)(2), the September 16, 1980, House Interior Committee Report on the Regional Act on pages 52 and 53 states as follows:

> "Section 7(d)(2) authorizes BPA to establish a special rate for a direct-service industrial customer if (1) the customer's primary resource consists of raw materials indigenous to the region, and (2) all power sold to such customer may be interrupted, curtailed, or withdrawn to meet firm loads in the region. The committee is aware of only one direct-service industrial customer, the Hanna Nickel Mining and Smelting Company, Riddle, Oregon, which would meet the criteria of this paragraph."

The July 30, 1979, Senate Report on S. 885 on page 32 states as follows:

> Section 7(d)(2) - The Administrator is authorized to establish a special rate applicable to an existing direct service industrial customer whose continued operation would otherwise be threatened if: (1) it primarily uses raw materials which are indigenous to the region such as nickel ore, and (2) it accepts a contract similar to its existing modified firm power sales contract with the Administrator which provides that all the customer's power provides reserves to meet firm loads in he region. The Committee is aware of only one direct service customer, Hanna Nickel Mining and Smelting Co., Riddle, Oreg., which would fit the criteria of this section (d)(2). The Committee intends that this provision will apply only to that customer."

The administrative record contains the following oral and written material on the request of Hanna:

a. Pre-filed Direct Testimony of Herbert D. Wedge, for the Hanna Mining Company, April 8, 1981.

b. Excerpts from the Official Report of Proceedings, BPA's Proposed Rate Adjustments, April 8,1981, Volume XIII, pp. 2326-2358.

c. Additional information submitted by the Hanna Nickel Smelting Company by David S. Baumgartner, Law Department in response to cross examination on April 8, 1981 of Mr. Wedge.

d. Brief of the Hanna Nickel Smelting Company filed by David S. Baumgartner, attorney for Hanna Nickel Smelting Company, May 4, 1981.

In the above record materials, Hanna submitted information showing adverse impacts on Hanna's operations would result from increased power costs if BPA's proposed IP-1 rates were made applicable to its sales to Hanna. BPA reviewed all information made a part of the Official Record and considered the effects a special rate for Hanna would have on BPA's other obligations under the Regional Act.

Based upon this review, I found that Hanna will experience adverse impacts if BPA's proposed IP-1 rate is made applicable to Hanna. I have also concluded that a special rate for Hanna will not adversely impact BPA's other obligations under the Regional Act. I have therefore approved, for application solely for sales to Hanna, a special rate under Section 7(d)(2) of the Regional Act.

Establishment of a special rate requires that Hanna be offered a special class of service which it will receive during the time the special rate is applicable to its purchases. Hanna will be offered a special class of power consisting of one-half nonfirm energy and one-half 'junior firm' power. BPA will supply advance energy, shape FELCC, and otherwise operate its resources to provide the same quality of service to the one-half of Hanna's load normally served with nonfirm energy as BPA provides to the top quartile of other industrial customer loads. BPA will supply such services to the extent the operating program developed under provisions of the Coordination Agreement indicates that BPA can obtain return of the energy advanced to Hanna by restricting, if necessary, the 'junior firm' power portion of Hanna's load that otherwise would be served during the period covered by the operating program in order to serve firm loads. The entire Hanna load will be restricted prior to actual restriction of service to any priority firm loads. All of Hanna's load may be interrupted for up to 6 hours in a 24-hour period to provide forced outage reserves for BPA.

BPA has determined that by Hanna accepting another quartile of interruptible power, BPA can forego a purchase of 26 average megawatts of firm power which would otherwise be necessary to cover a portion of the firm energy deficit of the Federal base system. The cost of this purchase as included in the determination of the purchase power costs assigned to the Federal base system in the COSA are $6.9 million.

By accepting a special class of service, Hanna will not be providing the same class of reserves as other direct-service industrial customers. The capacity reserves being provided are probably of equal or somewhat greater value than standard direct-service industrial customer capacity reserves. But the second quartile of Hanna's load will receive the same class of service as the top quartile of othe direct-service industrial loads and all second quartile loads of direct-service industrial customers would be restricted before restricting Hanna's bottom two quartiles of 'junior firm.' Therefore, Hanna will not be supplying energy reserves through restriction rights to its second quartile. The rates applicable to all other BPA customers have been determined as though Hanna were a standard direct-service industrial customer. Accordingly, if the special Hanna rate were subsidized by other purchasers, it would only be to the extent that rates to other customers included a charge for recovery of credit given to Hanna in recognition of energy reserves no longer being provided by service to Hanna's second quartile. To eliminate this potential subsidy, the $6.9 million cost savings has been reduced by the amount of reserve credit associated with the value of energy reserves not provided by Hanna but paid for through other's rates. The net cost savings that will be realized by the special quality of service arrangement with Hanna is $5.7 million. The development of the Hanna Rate after subtracting the $5.7 million is shown on Table 23, WPRDS.

BPA was unable to reflect this cost savings in the purchase power costs that are included in the final repayment study. The rates to all customers other than Hanna were developed by including Hanna as a regular direct-service industrial customer load. The Hanna rate was developed by simply deducting the $5.7 million from the total costs assigned to Hanna's load under the standard methodology and a revised formula for the rate to Hanna was developed. Therefore, if Hanna is able to pay rates based on this methodology, the special rate in this filing will be a cost-based rate. Other BPA customers will be paying the same rates they would have paid had Hanna accepted the standard IP-1 rate. If a special rate and class of service is merited in the development of future rate filings, the cost savings will be reflected in the Repayment Study. The IP-1 rate and all other rates will be developed including Hanna as a regular direct-service industrial customer. Then the savings less reserves not provided by Hanna will be deducted from the Hanna rate.

If the quantity of power exchanged pursuant to Section 5(c) of the Regional Act and its associated costs equal the maximum amounts forecast by the staff, a cost-based rate for Hanna might still result in serious adverse impacts for Hanna. Conversely, if the $5.7 million net savings is credited to Hanna and the quantity and/or costs of exchange power are substantially less than the staff estimates, Hanna might actually receive a rate reduction.

To preclude these potentially undesirable results, the special Hanna rate schedule has both a ceiling and a floor. If the ceiling rate applies from the initial date of the exchange, Hanna will need to obtain significantly greater price per pound for its nickel as well as continue its efforts to cut costs and improve efficiency in order to avoid adverse impacts. The floor rate is the rate applicable to all direct-service industrial customers when there is no exchange.

BPA intends to include a surcharge in the Hanna contract that will recover costs of serving Hanna that are not recovered through application of the rate if there are such nonreimbursed costs and if (1) Hanna's sales price for nickel increases and/or (2) the Hanna operation realizes profits. The ceiling amount of the surcharge will be determined by calculating what Hanna's purchase power costs would have been under the standard direct-service industrial customer rate, subtracting $5.7 million and comparing this to actual billings to Hanna. If actual billings equal or exceed the remainder of the first part of the calculation, no surcharge would be due. The times and methods for applying the surcharge, if any, have not been determined but will be part of the Hanna contract. Also, independent audits and quarterly meetings among Hanna, State, Labor, and BPA to review plant operations and management will be conducted during the period of time Hanna is on a special rate.

X. 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 LRIC 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 Wholesale Power Rate Design Study and TRDS.

E. 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.

F. As demonstrated by the current, revised and final Repayment Studies, BPA needs wholesale power rate and transmission rate increases 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.

G. 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.

H. 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.

I. 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.

J. 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.

K. 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-1, IP-1, MP-1, CF-1, CE-1, NR-1, NF-1, RP-1, FE-1, and transmission rate schedules ET-2, UFT-2, FPT-2, and IR-1.

Issued at Portland, Oregon this 24th day of June, 1981.

Peter T. Johnson

Peter T. Johnson
Administrator

EXHIBIT A
TRANSMISSION RATE SCHEDULES

Set A Rates:

SCHEDULE FPT-2 - FORMULA POWER TRANSMISSION.

SECTION 1. Availability: This schedule supersedes FPT-1 and is available for existing and new Agreements which provide for firm transmission of electric power and energy using the Integrated Network Segment, and/or the PNW-PSW Intertie Segment. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as a firm availability of service is required.

SECTION 2. Rate:

A. Full-Year Service: The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge and Intertie Charge, as applicable and as specified in the Agreement.

1. Main Grid Charge: The Main Grid Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $0.0200 per mile;

b. Main Grid Integration Terminal Factor - $0.16;

c. Main Grid Miscellaneous Facilities Factor - $0.89;

d. Main Grid Terminal Factor - $0.16; and

e. Main Grid Delivery Terminal Factor - $0.25.

2. Secondary System Charge. The Secondary System Charge shall be the sum of one or more of the following factors associated with deliveries at 115 kV as specified in the Agreement:

a. Secondary Transformation Factor - $1.41;

b. Secondary System Integration Terminal Factor - $0.41;

c. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $0.1029 per mile;

d. Secondary System Intermediate Terminal Factor - $0.41;

e. Secondary System Delivery Terminal Factor - $0.48.

3. Intertie Charge - for use of Intertie facilities - $3.56.

B. Partial-Year Service: The monthly charge per kilowatt of capacity shall be as specified in Section 2.A. for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

a. during months for which service is specified, the monthly charge defined in Section 2.A., and

b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

SECTION 3. Determination of Transmission Demand: Unless otherwise stated in the agreement, the factor to be used in determining the kilowatts of Transmission Demand is the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month; or

C. the Ratchet Demand.

SECTION 4. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

SCHEDULE ET-2 - ENERGY TRANSMISSION.

SECTION 1. Availability: This schedule supersedes ET-1 and is available for nonfirm transmission of non-Federal electric energy using excess capacity of the FCRTS. This rate is not available for the transmission of energy that is used to meet firm obligations on a planning basis, nor for energy which cannot be interrupted.

SECTION 2. Rates: The charge for nonfirm transmission of non-Federal nonfirm electric energy shall be based on the following rates.

	Mills/kWh
1. Delivery Over Integrated Network	0.97
2. Delivery Over the PNW-PSW Intertie	1.46
3. Delivery Over PNW-PSW Intertie including use of PNW Transmission System	2.43

SECTION 3. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

SCHEDULE UFT-2 - USE-OF-FACILITIES TRANSMISSION.

SECTION 1. Availability: This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. This schedule is not appropriate for new agreements for service over the Integrated Network Segment, or the PNW-PSW Intertie Segment.

SECTION 2. Rates: The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specified facilities. Such Annual Cost shall be determined in accordance with Section 3.

SECTION 3. Determination of Transmission Rate:

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and are used to transmit electric power and energy thereunder:

1. Capital cost of each such facility as specified in the most recently published plant investment records of BPA which are issued in support of the Federal Columbia River Power System financial statement.

2. Annual Interest and Amortization Ratios for each such facility using the most recent system average cost factors developed from actual Interest and Amortization costs for specific categories of FCRTS facilities and from data included in the financial statement.

3. Operation, maintenance, administrative and general, and general plant costs of such facilities using the most recent system average costs for specific categories of FCRTS facilities.

4. The yearly noncoincidental peak demands of all users of such facilities.

B. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each of the FCRTS facilities used. The Annual Cost per kilowatt of each facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{(I \times R) + B}{D}$$

Where B = Operation, maintenance, administrative and general, and general plant cost of such facility as determined in A.3.

I = Capital cost of such facility as determined in A.1.

R = Annual Interest and Amortization Ratio for such facility as determined in A.2.

D = The sum of the yearly noncoincidental demands on the facility as determined in A.4.

The Annual Cost per kilowatt of facilities listed in the Agreement which are owned by another entity, and used by BPA for making deliveries to the Transferee, shall be determined from the costs specified in the Agreement between BPA and such other entity.

SECTION 4. Determination of Transmission Demand: Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. the Ratchet Demand.

SECTION 5. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

General Transmission Rate Schedule Provisions:

1. Interpretation. The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. Bonneville Service Area. The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;

b. provide service to the BPA wholesale power and wheeling customers;

c. provide interregional transmission facilities; or

d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. Availability of Transmission Service. Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identifed in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. Billing Details.

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth percent (0.25%) of the amount unpaid or \$50. Thereafter, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

5. Definitions. Capitalized terms that are used in the Transmission Rate Schedules shall be as defined below, or, if not so defined, as defined in the Agreement.

a. Agreement: The transmission agreement to which this exhibit is attached.

b. Connection Point: Refers collectively to the following:

(1) Point of Integration (POI): Connection points where a non-Federal project is integrated with the FCRTS.

(2) Point of Delivery (POD): Connection points where power is delivered to a customer from the FCRTS. The power may be Federal or non-Federal.

(3) Point of Exchange (POE): Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. Electric Power (or simply Power if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. Firm Transmission Service: Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. Interest and Amortization Ratio: The annual interest and amortization costs of the Federal Columbia River Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

f. Main Grid: That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

g. Main Grid Delivery Terminal: 230 kV Terminal Facilities associated with a Point of Delivery.

h. Main Grid Distance: The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

i. Main Grid Integration Terminal: The Main Grid Terminal Facilities located at the Point of Integration.

j. Main Grid Miscellaneous Facilities: Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

k. Main Grid Terminal: Terminal facilities on the Main Grid adjacent to the Secondary System.

l. NonFirm Transmission Service: Service for which BPA will accept power only when it determines excess capacity is available. Once BPA accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

m. Ratchet Demand: The maximum past or present demand established during the previous 11 billing months based on the highest scheduled demand during that time.

n. Secondary System: That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

o. Secondary System Delivery Terminal: A Point of Delivery from a Main Grid substation at 115 kV or 69 kV, or a terminal located at a Point of Delivery from the Secondary System.

p. Secondary System Distance: The number of circuit miles of Secondary System transmission lines between the Main Grid and the Point of Delivery or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

q. Secondary System Integration Terminal: The first Terminal Facility in the Secondary System.

r. Secondary System Intermediate Terminal: The final Terminal Facilities in the Secondary System.

s. Secondary Transformation: Transformation from Main Grid to Secondary System facilities.

Set B Rates:

SCHEDULE IR-1 - INTEGRATION OF RESOURCES.

SECTION 1. Availability. This schedule is available for the integration of non-Federal resources by the Integrated Network Segment of FCRTS and for firm transmission over the Pacific Northwest-Pacific Southwest Intertie. This schedule is available only to utilities who agree to convert all firm transmission agreements using the Integrated Network and Intertie Segments (except Columbia Storage Power Exchange and other agreements as mutually agreed) to interim agreements consistent with this rate schedule.

SECTION 2. Rate.

a. Network Service: The monthly charge shall be the sum of:

(1) $0.1749 per kilowatt of Network Billing Demand, and

(2) $0.00056 per kilowatthour of Network Billing Energy.

b. Intertie Service: The monthly charge for firm service over the PNW - PSW Intertie shall be the charges in 2(a) plus the sum of:

(1) $0.3024 per kilowatt of Intertie Billing Demand, and

(2) $0.00081 per kilowatthour of Intertie Billing Energy.

SECTION 3. Determination of Billing Demand and Billing Energy. The Billing Demand for the Network and for the Intertie shall be as specified in the Agreement. The Network Billing Energy shall be all power scheduled to the Integrated Network from resources specified in the Agreement. The Intertie Billing Energy shall be all firm energy scheduled over the Intertie pursuant to the terms of the Agreement.

SECTION 4. General Provisions. This Rate Schedule shall continue in effect until July 1, 1982. This schedule shall not be used for long-term agreements. The Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS
(GTRSP)
FOR SET B TRANSMISSION SCHEDULES

1. General: This GTRSP applies to any and all Set B Rate Schedules. The provisions in the Interim IR Agreement to which this GTRSP is attached as an exhibit shall be part of this GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the provisions in the Agreement shall prevail.

2. Availability: Any capacity, in the Federal Columbia River Transmission System (FCRTS) which BPA determines to be in excess of the capacity required to transmit Federal power and previous firm obligations of non-Federal power, will be made available to all utilities on a fair and nondiscriminatory basis. Charges for the use of the FCRTS will be as identified in the Transmission Schedules.

3. Billing Details:

a. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

b. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth (0.25) percent of the amount unpaid or \$50. Thereafter, a charge of one-twentieth (0.05) percent 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 do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusines day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

c. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

d. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

4. Definitions: Capitalized terms (other than titles, proper nouns, and other words which normally have the first letter capitalized) and expressions in "quotes" that are used in Transmission Schedules, GTRSP, or in the Agreement shall be as defined below, or if not so defined, as defined in the Agreement. If a definition in the Agreement is in conflict with a definition below, the definition in the Agreement shall prevail.

a. Agreement: The interim, 1 year Integration of Resources Agreement to which this GTRSP is attached as an exhibit.

b. "approved point of connection:" Those points of connection which BPA and the customer using SET B Transmission Schedule agree are reasonable points of connection.

c. BPA: The Bonneville Power Administration, its Administrator, or his staff to which he has delegated certain responsibilities.

d. Contract Year - measn the period of time commencing at 12:01 a.m., on July 1, 1981, and ending at 12:00 p.m., on June 30, 1982.

e. FCRTS: The Federal Columbia River Transmission System which includes those transmission facilities located within the Pacific Northwest that BPA has constructed or acquired for marketing Federal power or for transmitting non-Federal power.

f. "firm non-Federal resource:" The resource that a non-Federal utility identifies in the Pacific Northwest Utilities Conference committee's West Group Forecast and is required to meet that utilities' firm loads and capacity reserves. Those resources that provide a surplus in a particular year may also be considered a "firm non-Federal resource" on a case by case basis if other non-Federal customers in the same class have deficits which can be met by the surplus.

g. FPT Schedule: The Formula Power Transmission Rate Schedule identifies 14 different rates for various transmission facilities.

h. GTRSP: The General Transmission Rate Schedule Provisions supplements various Rate Schedules.

i. Intertie Service: That transmission service provided by the PNW-PSW Intertie which consists of 2-500kV and 1-800kV transmission lines between the Columbia River and the southerm Oregon border.

j. Network Service: That transmission service provided by the Network Segment of the FCRTS.

k. Pacific Northwest: (1) the region consisting of the States of Oregon, Washington, and Idaho, the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and (2) any contiguous areas, not in excess of seventy-five airline miles from the area referred to above, which are a part of the service area of a rural electric cooperative customer that is served by the Administrator and has a distribution system from which it serves both within and without such region.

l. Power: electric peaking capacity, or electric energy or both.

m. Transmission Schedules: Any of the various transmission rate schedules identified in Set B Transmission Schedules.

n. UFT Schedule: The Use of Facilities Rate Schedule which identifies the methodology to use for developing a rate for proportional use of specific facilities.

5. General Provisions: This GTRSP for Set B Transmission Schedules has a limited purpose for a limited time, probably 1 year, during which a new transmission policy will be developed. Consequently, this GTRSP is expected to be superseded within 1 year.

EXHIBIT B

Wholesale Power Rate Schedules and General Rate Schedule Provisions

SCHEDULE PF-1 - PRIORITY FIRM POWER RATE

SECTION 1. Availability: This schedule is available for the purchase of firm power to be used within the Pacific Northwest for resale or for direct consumption by public bodies, cooperatives, Federal agencies, and investor-owned utilities participating in the exchange under Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). This schedule supersedes Schedule EC-8 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge:

(1) for the billing months September through March: 7.4 mills per kilowatthour of billing energy.

(2) for the billing months April through August: 6.9 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. For any purchaser not designated to purchase under subsection 3(b), 3(c), or 3(d):

(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. Designation of a purchaser to purchase on a computed demand basis will be according to this section unless the terms of an existing contract executed after December 5, 1980 provide otherwise. For any purchaser designated by BPA to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase BPA's obligation to deliver firm power to such purchaser in an amount in excess of BPA's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that 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 billing 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 BPA for a specified period of time.

c. For any purchaser 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:

(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. For any purchaser participating in the exchange under Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act:

(1) sixty percent of the energy associated with the utility's residential load as specified in the contract for each billing period;

(2) the demand calculated by applying the load factor, determined as specified in the contract, to the energy in 3(d)(1) for each billing period.

SECTION 4. Determination of Billing Demand and Billing Energy:

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

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

(2) the billing energy for the month shall be factor 3(a)(3) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3).

b. For a purchaser governed by subsection 3(b):

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

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

c. For 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 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. <u>At-Site Power</u>: At-site power purchased for consumption by a purchaser shall be used within 15 miles of the powerplant specified in the power sales contract. At least 90 percent of any at-site power purchased for resale shall be used within 15 miles of the specified powerplant.

The monthly demand charge for at-site firm power will be the monthly demand charge for priority firm power reduced by $0.257 per kilowatt of billing demand.

At-site priority firm power is made available only for those utility customers purchasing at-site firm power under existing contracts. At-site priority firm power may be purchased by such utility customers under new contracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by BPA. This use-of-facilities charge shall be in addition to the charge determined by the application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

c. <u>Low-Density Discount</u>: A predetermined discount will be applied each month of a calendar year to the charges for power purchased under contracts between BPA and its 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 per mile of line. This calculation of such ratio will be made using the customer's entire system. Provided that the purchaser's ratio of residential consumers per mile of line does not exceed ten, this 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.

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 $0.13 per kilowatthour.

SECTION 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE IP-1 - WHOLESALE POWER RATE FOR INDUSTRIAL FIRM POWER

SECTION 1. Availability: This schedule is available for the purchase by existing direct-service industrial customers of industrial firm power and/or authorized increase on a contract demand basis and for auxiliary power requested by the purchaser and made available an auxillary demand by BPA on an intermittent basis. This rate schedule supersedes Schedule IF-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge:

The greater of:

(1) for the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing, or

(2) for the billing months September through March: [1.7 + (X/2465)] mills per kilowatthour of billing energy; for the billing months April through August: [1.6 + (X/2480)] mills per kilowatthour of billing energy.

Where X = the actual month's cost in thousands of dollars incurred by the Administrator pursuant to Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

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. measured energy.

SECTION 4. Determination of Billing Demand and Billing Energy: The billing demands for industrial firm power and authorized increase, respectively, and for auxiliary power requested by the purchaser and made available by BPA as an auxiliary demand on an intermittent basis will be the lowest of the respective operating demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such 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) $0.33 per kilowatt of billing demand.

(2) 2.3 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 appropriate demand (operating, curtailed, or restricted) for each month by 1 percent for 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in 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. At-Site Power: At-site industrial firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site industrial firm power will be the monthly demand charge for industrial firm power reduced by $0.257 per kilowatt of billing demand.

At-site industrial firm power is made available only for those industrial customers purchasing at-site industrial firm power under existing contracts. At-site industrial firm power may be purchased by such industrial customers under new contracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by BPA. The use of facilities charge shall be in addition to the charge determined by application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

SECTION 6. Unauthorized Increase: Any amount by which any 60-minute clock-hour integrated demand exceeds that sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.13 per kilowatthour.

SECTION 7. Special Conditions - Advance of Energy: BPA may elect to advance energy under terms and conditions of the purchaser's power sale contract.

SECTION 8. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE MP-1 - WHOLESALE POWER RATE FOR MODIFIED FIRM POWER.

SECTION 1. Availability: This schedule is available for the purchase by existing direct-service industrial customers of modified firm power on a contract demand basis for direct consumption by existing direct-service industrial customers until existing contracts terminate. This schedule is also available for the purchase of authorized increase power on a contract demand basis. This rate schedule supersedes Schedule MF-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge:

The greater of:

(1) for the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing, or

(2) for the billing months September through March: [1.7 + (X/2465)] mills per kilowatthour of billing energy; for the billing months April through August: [1.6 + (X/2480)] mills per kilowatthour of billing energy.

Where X = the actual month's cost in thousands of dollars incurred by the Administrator pursuant to Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

SECTION 3. Billing Factors: The factors to be used in determining the billing for power purchases under this rate schedule are as follows:

a. contract demand;
b. curtailed demand;
c. restricted demand;
d. measured energy.

SECTION 4. Determination of Billing Demand and Billing Energy: The billing demand for modified firm power and authorized increase, respectively, will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

SECTION 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in 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. At-Site Power: At-site modified firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site modified firm power will be the monthly demand charge for modified firm power reduced by $0.257 per kilowatt of billing demand.

At-site modified firm power will be made available under existing contracts, providing for at-site modified firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by BPA. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by BPA. This use of facilities charge shall be in addition to the charge determined by application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

SECTION 6. Unauthorized Increase: Any amounts by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour (before adjustment for power factor) plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.13 per kilowatthour.

SECTION 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE CF-1 - WHOLESALE FIRM CAPACITY RATE.

SECTION 1. Availability: This schedule is available for the 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 F-7 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Contract Year Service: $25.44 per kilowatt per year of contract demand.

b. Contract Season Service: $11.76 per kilowatt per season of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by $0.029 per kilowattmonth of billing demand for each 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 effective for such month. If, however, BPA does not require the delivery of peaking replacement energy by the purchaser during certain periods, the additional charge above will not be made for such periods.

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. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE CE-1 - 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 F-8 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate: $0.56 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 $0.22 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. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE NR-1 - NEW RESOURCE FIRM POWER RATE.

SECTION 1. Availability: This schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial purchasers who purchase power under rate Schedules IP-1 or MP-1.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge:

(1) for the billing months September through March: 30.8 mills per kilowatthour of billing energy.

(2) for the billing months April through August: 24.7 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. For any purchaser not designated to purchase under subsection 3(b) or 3(c):

(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. Designation of a purchaser to purchase on a computed demand basis will be according to this section unless the terms of an existing contract executed after December 5, 1980 provide otherwise. For any purchaser designated by BPA to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase BPA's obligation to deliver firm power to such purchaser in an amount in excess of BPA's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that 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 billing 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 BPA for a specified period of time.

c. For any purchaser 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:

(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 3(a):

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

(2) the billing energy for the month shall be factor 3(a)(3) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3).

b. For a purchaser governed by subsection 3b:

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

(2) the billing energy for the month shall be factor 3(b)(5) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3). Factor 3(b)(5) shall not exceed factor 3(b)(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 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 $0.13 per kilowatthour.

SECTION 7. General Provisions: Sales of power under this Schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE NF-1- WHOLESALE NONFIRM ENERGY RATE.

SECTION 1. Availability: This schedule is available for the purchase of nonfirm energy both inside and outside the Pacific Northwest. This schedule is also available for energy delivered for emergency use under the conditions set forth in Section 5.1 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 H-6 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Nonfirm Energy Rate: The rate shall be the average cost of transmission which is 2.0 mills per kilowatthour, plus one of the following:

(1) the diurnally differentiated average cost of power from hydroelectric facilities, which is 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m.; and 3.0 mills per kilowatthour for all other hours of the year, or

(2) the cost of a power purchase in mills per kilowatthour incurred since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full, if they were not substantially full on that date, to the extent such purchase cost is unrecovered, or

(3) BPA's cost of other resources in mills per kilowatthour operated since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full, if they were not substantially full on that date, to the extent such purchase cost is unrecovered, or

(4) a weighted average in mills per kilowatthour based on costs from the preceding categories.

As an amount of energy associated with any given power purchase or resource is used to derive a charge for a sale of an equivalent amount of nonfirm energy, that purchase or resource cost will no longer be used to determine the rate for subsequent sales.

b. Contract Rate: For contracts which refer to this schedule for determining the value of energy, the rate is 9.6 mills per kilowatthour.

SECTION 3. Delivery: BPA shall determine the availability of energy hereunder and the rate of delivery thereof.

SECTION 4. General Provisions: Sales of energy under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE RP-1 - 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. This rate schedule supersedes Schedule EC-9 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $12.57 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $3.47 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge: 62.1 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. 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 $0.13 per kilowatthour.

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 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 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 7. General Provisions: Sales of power under this Schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE FE-1 - WHOLESALE FIRM ENERGY RATE.

SECTION 1. Availability: This schedule is available for contract 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 J-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate: 10.0 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. 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 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. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE SI-1 - SPECIAL INDUSTRIAL POWER RATE

SECTION 1. Availability: This schedule is available for the Hanna Nickel Smelting Company's purchase of a special class of industrial power and/or authorized increase on a contract demand basis and for additional power requested by the purchaser and made available as authorized increase by Bonneville 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.: $2.80 per kilowatt of billing demand.

(2) For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.44 per kilowatt of billing demand.

(3) All other hours: No demand charge.

b. Energy Charge:

The greater of:

(1) For the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing energy; or

(2) For the billing months September through March:

[(X/2465) - 4.8] mills per kilowatthour;

for the billing months April through August:

[(X/2480) - 4.9] mills per kilowatthour

Where X = the actual monthly costs in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Regional Act. But the energy charge is not to exceed 10.6 mills per kilowatthour in any month, excluding any surcharges that will be made applicable pursuant to provisions of the contract to recover the costs of services if conditions affecting profitability of the purchaser's operation improves.

SECTION 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. contract demand;

b. curtailed demand;

c. restricted demand;

d. measured energy.

SECTION 4. Determination of Billing Demand and Billing Energy: The billing demands for this special class of industrial power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distribute proportionately among the respective demands for each hour each such 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) $0.33 per kilowatt of billing demand.

(2) 2.3 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 appropriate demand (operating, curtailed, or restricted) for each month by 1-percent for 1-percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in 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: Any amount by which any 60-minute clock-hour integrated demand exceeds that sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.13 per kilowatthour.

SECTION 7. Special Conditions - Advance of Energy: BPA may elect to advance energy under terms and conditions of the purchaser's power sale contract.

SECTION 8. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Consevation Act, and the applicable General Rate Schedule Provisions.

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 net 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.

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 such purchaser and one or more priority and 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 miminize 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 is capacity which BPA assures will be available to a purchaser on a contract demand basis except when operation of 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 priority and new resource firm power, and (b) the following:

(1) the restrictions given in the Restriction of Deliveries Section of the Power Sales Provisions of the contract.

(2) when a restriction is made necessary because of the operation of generation or transmission facilities used by BPA to serve such purchaser and one or more priority and 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, or industrial firm power 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 Uncontollable 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. Measured Demand:

a. 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.

b. 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 3.2 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 the largest of the hourly amounts of such class of power which are scheduled for delivery to the purchaser during each time period specified in the applicable rate schedule.

SECTION 2.3. 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. <u>Determination of Assured Capability</u>: 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) Thermal Generating Facilities: The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such 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 2.4. 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 2.5 of the General Rate Schedule Provisions.

SECTION 2.5. 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, 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, modified firm power, or industrial firm power may curtail its demand in accordance with Section 1.5 of the General Rate Schedule Provisions.

SECTION 3.1. 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 3.2. 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 4.1 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 Bonnevillle, be extended beyond the initial 3 month period for such additional time as is justified by the developmental character of the operations.

SECTION 5.1. 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-1 and Emergency Capacity Schedule CE-1 for any electric energy 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 6.1. 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 7.1. 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. Thereafter a charge on 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 8.1. Approval of Rates: Schedules of rates and charges, or modifications thereof, for electric power sold by BPA shall become effective on a final basis after confirmation and approval by the Federal Energy Regulatory Commission. Pending the establishment of procedures by the Commission to approve rates on a final basis, the entity or entities having been designated by the Secretary of Energy prior to December 5, 1980, shall have authority to confirm and approve schedules of rates and charges on an interim basis.

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. Temporary Curtailment of Contract Demand: The reduction of charges for power curtailed pursuant to the purchaser's contract and Section 1.5 and 2.5 hereof shall be applied in a uniform manner.

SECTION 11.1. General Provisions: The Wholesale Rate Schedules and General Rate Schedule Provisions of the BPA Power Administration effective July 1, 1981, supersede in their entirety BPA's Wholesale Power Rate Schedule Provisions effective December 20, 1979.