1983 FINAL RATE PROPOSAL

EXECUTIVE SUMMARY
OF
ADMINISTRATOR'S RECORD
OF
DECISION

BPA

BONNEVILLE POWER ADMINISTRATION
U. S. DEPARTMENT OF ENERGY

September 1983

BONNEVILLE POWER ADMINISTRATION
WHOLESALE POWER RATE INCREASE
Docket No. EF-84-2011-000
ERRATA TO ADMINISTRATOR'S RECORD OF DECISION
CHANGES TO FILED RATE SCHEDULES

The power bill shall reflect the distribution of the kilowatthours of billing energy among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE IP-83 RATE FOR BASIC SERVICE:

All sales of Industrial Firm Power for which there is no contract specifying use of the Premium Industrial Rate or the Industrial Incentive Rate shall be made at the Standard Industrial Rate.

If the purchaser elects to purchase Industrial Firm Power under the Premium Industrial Rate, BPA and the purchaser shall execute a contract specifying the period of time for which the Premium Industrial rate shall be effective.

The Industrial Incentive Rate shall only be applied to sales of Industrial Firm Power made pursuant to contracts specifying use of the Industrial Incentive Rate. Prior to applying the Industrial Incentive Rate, BPA and the purchaser shall contractually specify the terms and conditions under which the incentive rate shall apply. The contract with the purchaser shall specify:

A. the period of time for which the Industrial Incentive Rate is to be applied (such period being for no less than 6 months or the end of the Rate Adjustment period, whichever comes first);
B. the Committed Demand;
C. the Committed Energy; and
D. the level of the demand and energy charges.

During any billing month only one of the three possible rates for Industrial Firm Power basic service may apply (Standard Industrial Rate, Premium Industrial Rate, and Industrial Incentive Rate). The rate in effect on the first day of the billing month shall remain in effect for the entire billing month.

SECTION V. ADJUSTMENTS:

A. Value of Reserves

A monthly billing credit for the value of the reserves provided by purchasers of Industrial Firm Power under the Standard Industrial Rate and the Premium Industrial Rate shall be:

1. \$0.23 per kilowatt of billing demand; and
2. 1.6 mills per kilowatthour of billing energy.

The credit for power purchases under the Standard Industrial Rate and the Premium Industrial Rate shall be applied to the same billing factors which are used to determine the billing for power purchased under sections III.B.1, III.B.2, and III.C.1 of this rate schedule. No value of reserves credit shall be applied to that portion of the purchaser's demand subject to curtailment charges under section III.B.3 of this rate schedule. In addition, no value of reserves credit shall be applied to those purchases subject to unauthorized increase charges under section III.B.4, above.

No value of reserves credit shall be applied to purchases of Industrial Firm Power under the Industrial Incentive Rate.

B. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

C. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under the Standard Industrial Rate and the Premium Industrial Rate.

For this rate schedule, the variable ECP in the Exchange Adjustment calculation shall have a value of .521.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the IP-83 rate is 100 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.9 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 34.0 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

Sales of power under this schedule shall be subject to the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

b. Offpeak Industrial Hanna Rate

If the purchaser is being served under the Offpeak Industrial Hanna Rate and requests more than 10 percent of Contract Demand during other than the specified offpeak period, such deliveries may be billed as an unauthorized increase. BPA shall make the determination as to how the unauthorized increase shall be billed.

5. Transitional Service:

If the purchaser requests billing on a Measured Demand basis pursuant to section 4 of the power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the weighted average of the daily Measured Demands as adjusted for power factor. However, at no time during the period of restoration, as defined in section 4(e) of the power sales contract, shall the daily demand be lower than any previous such demand during such period. Should the Measured Demand for any day during the period of restoration be lower than the daily demand for the previous day, the previous day's demand shall be used as the daily demand for such day.

B. Billing Energy

The billing energy under both the Standard and Offpeak Industrial Hanna Rates shall be the Measured Energy for the billing month.

The power bill shall reflect the distribution of the kilowatthours of billing energy among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE IH-83 RATE:

The purchaser may select one of two service options, standard service or offpeak service. BPA will provide standard service under the Standard Industrial Hanna Rate and offpeak service under the Offpeak Industrial Hanna Rate. Unless BPA receives a formal request for service under the Special Offpeak Industrial Hanna Rate, all service will be standard service provided under the Standard Industrial Hanna Rate. To change the type of service provided and the associated rate, the purchaser shall submit a formal request for service under the preferred rate option in accordance with the terms of the purchaser's power sales contract. Once a purchaser has elected to purchase under one of the two options, all purchases of special industrial power shall be subject to the terms and conditions of that rate option until such time as the purchaser requests the other type of service.

SCHEDULE CF-83

FIRM CAPACITY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Firm Capacity without energy on a Contract Demand basis. BPA may supply Firm Capacity:

A. on a contract year basis (all 12 months of the year);
B. on a contract season basis (June 1 through October 31); or
C. on a general basis (where the months during which Firm Capacity will be supplied are specified in the power sales contract).

This schedule supersedes Schedule CF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. <u>Contract Year Service</u>

$44.76 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.73 per kilowatt of Contract Demand.

B. <u>Contract Season Service</u>

$12.10 per kilowatt per season of Contract Demand, billed monthly during the contract season at the rate of $2.42 per kilowatt of Contract Demand.

C. <u>General Service</u>

1. for the billing months December through April:
   $5.57 per kilowatt of Contract Demand;

2. for the billing months May through November:
   $2.42 per kilowatt of Contract Demand,

BPA shall bill purchasers of general Firm Capacity service at the applicable monthly rate, as given in C.1 and C.2, above. Bills shall be rendered only for the months during which BPA has contracted to supply Firm Capacity to the purchaser.

SCHEDULE NR-83

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest.

New Resource Firm Power is available to those investor-owned utilities under net requirements contracts purchasing firm power for resale, direct consumption, or use in construction, test and start up, and station service.

New Resource Firm Power is also available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any increase in energy consumption of a load as defined in section 3.(13) of the Pacific Northwest Electric Power Planning and Conservation Act as interpreted in Notice of Final Action (46 F.R. 44353)(September 3, 1981).

In addition, BPA may make this rate available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedules NR-2 and FE-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: $5.57 per kilowatt of billing demand;

2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: $2.42 per kilowatt of billing demand;

3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March: 26.3 mills per kilowatthour of billing energy;

2. for the billing months April through August: 21.0 mills per kilowatthour of billing energy.

6. Operating Demand

The Operating Demand is that demand which is established in accordance with section 5(b) of the purchaser's power sales contract. For the purpose of the rate schedules and these GRSP's two other terms are defined: the Forecasted Operating Demand and the Monthly Operating Demand.

Forecasted Operating Demand:

The Forecasted Operating Demand for each direct-service industrial purchaser is that demand which was forecast for the development of rates. Those Forecasted Operating Demands are presented below for Period A (November 1, 1983, through June 30, 1984), Period B (July 1, 1984, through June 30, 1985), and Period C (July 1, 1985 until the next Rate Adjustment Date).

		PERIOD A	PERIODS B & C
a.	Aluminum Company of America	472.0 MW	469.0 MW
b.	Arco Metals Company	262.0 MW	282.0 MW
c.	The Carborundum Company	0.2 MW	0.2 MW
d.	Crown Zellerbach Corporation	16.6 MW	16.6 MW
e.	Elkem Metals Company	0.0 MW	0.0 MW
f.	Georgia-Pacific Corporation	25.9 MW	27.8 MW
g.	Intalco Aluminum Company	452.0 MW	452.0 MW
h.	Kaiser Aluminum & Chemical Corporation	426.0 MW	516.0 MW
9.	Martin Marietta Aluminum, Inc.	424.0 MW	412.0 MW
i.	Oregon Metallurgical Corporation	5.25 MW	5.25 MW
j.	Pacific Carbide and Alloys Company	6.7 MW	6.7 MW
k.	Pennwalt Corporation	57.5 MW	57.5 MW
l.	Reynolds Metals Company	580.0 MW	603.0 MW

Monthly Operating Demand:

The Monthly Operating Demand is used to compute the amount of the customer charge for each of BPA's direct-service industrial customers purchasing under the IP-83 Rate Schedule. The Monthly Operating Demand shall be determined by each purchaser and shall be submitted to BPA by November 1, 1983, for Period A, by July 1, 1984, for Period B, and by July 1, 1985, for Period C, if applicable. The purchaser shall determine its Monthly Operating Demand for each month of the rate period (Period A, Period B, and Period C) such that the average of the Monthly Operating Demands for each rate period shall equal the Forecasted Operating Demand for the period. The Monthly Operating Demand may not exceed, at any time, the purchaser's Operating Demand as specified in the power sales contract. If a purchaser does not make a submission to BPA, BPA shall assume that the purchaser will take its Forecasted Operating Demand in each month of the rate period.

C. BILLING ADJUSTMENTS

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or
b. are provided under more than one rate schedule

and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a poor power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Exchange Adjustment Clause

To the extent that the accounting net cost of exchange resources (the cost of the exchange resources to BPA minus the revenue collected from the exchange loads) differs from that forecast for development of rates, a rebate shall be given or a surcharge assessed to all those purchasing under rate schedules which include this adjustment (PF-83, IP-83, CF-83, and NR-83).

There will be an Exchange Adjustment for the period November 1, 1983, through June 30, 1984 (Period A), another such adjustment for the period July 1, 1984, through June 30, 1985 (Period B), and a third adjustment for the period July 1, 1985, until the next Rate Adjustment Date (Period C), provided BPA does not adjust its wholesale power rates on July 1, 1985.

Calculation and Application of the Exchange Adjustment:

The total amount of revenue which must be rebated or recovered in order for BPA to adjust for changes in the accounting net cost of the exchange shall be calculated for each exchange adjustment period according to the formula below. However, because the exchange adjustment is not being applied to the Surplus Firm Power Rate Schedule to which exchange costs have been allocated, the actual amount of revenue rebated or recovered will be less than the value of TAR.

$$TAR = (AEC - AER) - (FEC - FER)$$

where:

TAR = total amount of revenue underrecovery (or overrecovery) of the accounting net cost of the exchange for the exchange adjustment period;

AEC = actual total exchange cost for the period for which the exchange adjustment is being made; AEC includes exchange costs from the utilities whose average system cost (ASC) is deemed equal to the Priority Firm Power Rate (deeming utilities);

AER = actual exchange revenue for the relevant period; both AEC and AER will be calculated without considering the effect of the Exchange Adjustment Clause, but including the effect of the Supply System Adjustment Clause; AER includes exchange revenue from deeming utilities;

FEC = forecasted exchange cost;
for Period A, the value of FEC is equal to $634,610,000;
for Period B, the value of FEC is equal to $1,088,690,000;
for Period C, the value of FEC shall be calculated after BPA has determined the number of months in Period C;

FER = forecasted exchange revenue;
for Period A, the value of FER is equal to $536,901,000;
for Period B, the value of FER is equal to $809,201,000;
for Period C, the value of FER shall be calculated after BPA has determined the number of months in Period C;

Next, the rebate or surcharge for each customer class for each period shall be calculated.

$$CCEA = TAR * ECP$$

where:

CCEA = rebate or surcharge for each customer class for each exchange adjustment period; two values of CCEA shall be calculated for Firm Capacity service, one value for contract year and general Firm Capacity service and another for contract season service.

testimony to BPA. Interested parties shall be afforded a reasonable opportunity to examine the testimony of all witnesses. Written comments on the calculation of the proposed Supply System Adjustment will be accepted until close of business on June 1, 1984. BPA shall then evaluate all comments received. Comments and testimony should be directed to the proper calculation of the adjustment, not the appropriateness of the level of Supply System budgets or construction schedules. Consideration of comments and more current information, i.e., the Supply System Annual Budget for OY 1985 as of June 15, 1984, may result in the final adjustment differing from the proposed adjustment. Prior to implementing the adjustment, BPA shall notify all affected parties of the amount of the final adjustment.

4. Conservation Charge

BPA shall assess a charge on all purchasers who are party to any of BPA's conservation contracts which contain the conservation charge provision. That charge, established pursuant to section 32 of the General Conservation Contract Provisions (GCCP's), shall be assessed for each billing period. For these conservation charges, the billing periods shall be:

Period A: November 1, 1983, through June 30, 1984;
Period B: July 1, 1984, through June 30, 1985; and
Period C: July 1, 1985, until the next Rate Adjustment Date. Period C shall only occur if BPA does not adjust its wholesale power rates on July 1, 1985.

For metered requirements customers the charge shall be equal to:

COST * ACTLD

where:

COST = the cost in mills per kilowatthour for each conservation charge period; COST is equal to:

.179 for Period A; and
.370 for Periods B and C;

ACTLD = for Periods A and B, the actual non-BPA load for the operating year (July 1 through June 30) for each utility being assessed this charge; for Period C, the utility's actual non-BPA load in the months which constitute Period C; non-BPA load is defined below;

For computed requirements customers (including the investor-owned utilities) the charge shall be equal to:

(COST * ACTLD) + [Σ[(ACTLD / UTTL) * PAYMT * FACTOR]

i.e., Load Charge + Reimbursement Charge where:

COST	=	the cost in mills per kilowatthour for each conservation charge period; COST is equal to: .143 for Period A; and .248 for Periods B and C.
ACTLD	=	for Periods A and B, the actual non-BPA load for the operating year (July 1 through June 30) for each utility being assessed this charge; for Period C, the utility's actual non-BPA load in the months which constitute Period C; non-BPA load is defined below;
UTTL	=	the utility's actual total load for the operating year for Periods A and B; for Period C, the utility's actual total load in the months which constitute Period C;
PAYMT	=	direct payments (by BPA, a trustee, or other disbursing agent to a utility, its contractor, or its assignee) of funds budgeted to implement the Street and Area Lighting Program Agreement and/or the Residential Weatherization Conservation Program Agreement; PAYMT shall be equal to the sum of those payments, or applicable portions thereof, obligated for the period November 1, 1983, through the end of the contract charge period in question;
FACTOR	=	the amount of money to be collected from the Reimbursement Charge (as opposed to the Load Charge) for computed requirements purchasers, divided by the forecasted conservation acquisition expenditures for the computed requirements customers' non-BPA load; FACTOR is equal to: .068 for Period A; and .088 for Periods B and C.

(ACTLD / UTTL) * PAYMT shall be calculated for each period specified above. The reimbursement charge is calculated by summing (ACTLD / UTTL) * PAYMT for each period from OY 84 to the present and multiplying that sum by the factor for the present period. Thus, the reimbursement charge for each period is:

Period A: [(ACTLD 84 / UTTL 84) * PAYMT 84] * [.068]

Period B: [[(ACTLD 84 / UTTL 84) * PAYMT 84] + [(ACTLD 85 / UTTL 85) * PAYMT 85]] * [.088]

SCHEDULE FPT-83.3

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes FPT-2 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 3 years. It is available for firm transmission of electric power and energy using the FCRTS. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as firm availability of service is required.

SECTION II. RATES

A. <u>Full-Year Service</u>:

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge, and Intertie Charge, as applicable and as specified in the Agreement.

1. <u>Main Grid Charge</u>:

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

a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $.0326 per mile;

b. Main Grid Interconnection Terminal Factor - $.42.

c. Main Grid Terminal Factor - $.32;

d. Main Grid Miscellaneous Facilities Factor - $1.56;

1. <u>Secondary System Charge</u>:

The Secondary System Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $.1879 per mile;

b. Secondary Transformation Factor - $2.38;

c. Secondary System Intermediate Terminal Factor - $.76;

d. Secondary System Interconnection Terminal Factor - $.95.

SCHEDULE FPT-83.5

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY:

This schedule supersedes FPT-1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 5 years. It is available for firm transmission of electric power and energy using the FCRTS. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as firm availability of service is required.

SECTION II. RATES

A. Full-Year Service:

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge, and Intertie Charge, as applicable and as specified in the Agreement.

1. Main Grid Charge:

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

a. Main Grid Distance Factor - The amount computed by multiplying the Main Grid Distance by $.0326 per mile;

b. Main Grid Interconnection Terminal Factor - $.42.

c. Main Grid Terminal Factor - $.32;

d. Main Grid Miscellaneous Facilities Factor - $1.56;

2. Secondary System Charge:

The Secondary System Charge shall be the sum of one or more of the following factors as specified in the Agreement:

a. Secondary System Distance Factor - The amount determined by multiplying the Secondary System Distance by $.1879 per mile;

b. Secondary Transformation Factor - $2.38;

c. Secondary System Intermediate Terminal Factor - $.76;

d. Secondary System Interconnection Terminal Factor - $0.95.

e. Integrated Network:

Those transmission facilities which primarily perform the function of bulk transmission of electric power in the Pacific Northwest, excluding facilities not segmented to the Network in the Cost of Service Analysis used in BPA's rate development.

f. Main Grid:

As used in the FPT rate schedule, that portion of the FCRTS with facilities rated 230-kV and higher, exclusive of those designated as Interties.

g. Main Grid Distance:

As used in the FPT rate schedule, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

h. Main Grid Interconnection Terminal:

As used in the FPT rate schedule, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

i. Main Grid Miscellaneous Facilities:

As used in the FPT rate schedule, switching, transformation, and other facilities of the Main Grid not included in other factors.

j. Main Grid Terminal:

As used in the FPT rate schedule, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

k. Measured Demand. Except where deliveries are scheduled as hereinafter provided, the Measured Demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands delivered to a customer at each POD during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the Agreement. BPA, in determining the Measured Demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. For those Agreements to which BPA is a party and which provide for delivery of more than one class of electric power to the customer at any POD, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the Agreement. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

SUMMARY

Administrator's Record of Decision
1983 Wholesale Power and Transmission Rate Proposals
Bonneville Power Administration

The Administrator's Record of Decision traces the decisionmaking process used by the Administrator of the Bonneville Power Administration (BPA) in overseeing the development of BPA's proposed 1983 Wholesale Power and Transmission Rate Schedules. The Administrator's decisions are based on the record compiled during the rate adjustment proceedings. The record includes approximately 20,000 pages of written testimony, exhibits, transcripts from hearings and oral arguments, comments, and briefs. BPA is submitting the proposed rates to the Federal Energy Regulatory Commission (FERC) for final confirmation and approval. BPA also is asking FERC for interim approval of the rates so they may become effective November 1, 1983.

The rate proceedings opened on January 28, 1983, when BPA published in the FEDERAL REGISTER notices of intent to revise its wholesale power and transmission rates (47 FEDERAL REGISTER 4027 and 4028). BPA's initial proposal for revised rates was issued on March 28, 1983, (47 FEDERAL REGISTER 12,766 and 12,777). In accordance with the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), BPA held an evidentiary hearing on the proposed rate adjustments. The hearing commenced April 5, 1983, with a prehearing conference. Forty-two parties participated in the hearing. These included publicly owned and investor-owned utility customers, direct service industrial customers, Federal and State agencies, public interest groups, and Congressman James Weaver.

In addition to the formal hearing process, BPA provided for substantial public participation in developing the rates. Eight field hearings were held in April 1983 throughout the Pacific Northwest to allow public comment on the initial proposal. A second set of field hearings was held in July to solicit public comment on the record and the evidence developed during the formal hearings. BPA also received telephone calls and letters commenting on the rate proposal. BPA evaluated the extensive record in a document titled Evaluation of the Record, which was published August 18, 1983.

BPA is required to increase its rates to meet its financial obligations. BPA is required by law to recover its operating costs and repay with interest the government's investment in power facilities, conservation, and other programs. BPA developed a study of its financial situation to determine the amount of revenue required to meet these obligations. The study revealed that BPA needs revenue of approximately $5 billion during the November 1, 1983, to June 30, 1985, rate period. Current rates would produce revenues of $4.2 billion during this period. The average rate and average percentage rate increase, based on operating year (OY) 1985 loads, for various classes of customers that now purchase power from BPA are shown below:

Customer	Average Rate	Percentage Increase
Priority Firm (mills/kWh)	22.0	22.2
Industrial Firm(mills/kWh)	26.8	9.4
Firm Capacity		
Annual ($/kW/month)	3.73	21.9
Seasonal ($/kW/month)	2.54*	(4.5)
New Resource (mills/kWh)	29.2	(1.0)
Nonfirm		
Standard (mills/kWh)	18.5**	1.6
Spill (mills/kWh)	11.0**	22.0
Surplus Firm Power (mills/kWh)	31.2	(3.1)
Surplus Firm Energy (mills/kWh)	31.1	9.5
Integration of Resources		
Demand Charge ($/kW/yr)	3.75	78.7
Energy Charge (mills/kWh)	0.98	75.0

* Includes $.12 per kilowatt intertie charge.
** Applies to nonguaranteed service; add 1.8 mills/kWh for guaranteed service.

Preliminary Issues

The first step in the rate development process was to resolve a number of preliminary issues. These included a determination of loads during the rate period and resources available to meet those loads, development of a pre-rate period revenue forecast to assess BPA's financial position at the beginning of the rate period, and classification of costs between demand and energy.

The load forecast represents BPA's estimate of the expected total loads of its major customer groups. Issues raised during the rate proceedings relating to the load forecast primarily concerned the methodology for determining loads of BPA's direct service industrial (DSI) customers. The DSI load forecast used by BPA for the final proposal is based on a model that simulates the economic decision of whether to operate an aluminum company potline based on marginal production costs. This model was developed through informal technical sessions open to all parties. The forecast is based on two load scenarios, one of which reflects optimistic forecast assumptions and one which reflects pessimistic assumptions regarding aluminum price projections. As a result of evidence presented during the hearings and the recent recovery in the aluminum industry, BPA revised its weighting of the scenarios for the final proposal. Instead of averaging the two scenarios, BPA placed more weight on the optimistic scenario.

After the load forecast was developed, the resources necessary to meet that load were identified. The Regional Act created three distinct resource pools for the purpose of establishing rates prior to 1985. The first resource pool, the Federal base system (FBS), includes Federal Columbia River Power System (FCRPS) hydroelectric projects, the resources acquired by the Administrator under long term contracts in force at the time the Regional Act was implemented, and any resources acquired to replace any reduction in capability of FBS resources. The second resource pool consists of the power purchased under the Residential Exchange program. Under the exchange program, BPA purchases from each utility participating in the program an amount of power equal to a prescribed portion of the participant's residential and small farm load at the average cost of the participant's power system. BPA then sells an equal amount of power to the exchanging utility at the Priority Firm rate, which is the rate charged BPA preference customers. The third resource pool, the New Resource pool, includes all new resources acquired by BPA that are not FBS replacements.

BPA plans resources to meet critical period conditions, that is, water conditions equal to those during a historical period when the hydro system was able to generate the least amount of firm power. Studies by BPA and others in the Northwest have shown that the critical period, using the historical streamflow record, is usually the 42-month period beginning September 1, 1928, and ending February 29, 1932.

BPA has determined that it will have resources in excess of firm loads during the rate period. The method of determining the surplus affects the ultimate size of the resources used in the rate development process and the allocation of costs to BPA's customer classes. The Federal system is a flexible system and can shift energy production between hours, days, months, and years. In the initial proposal, BPA determined firm surplus for OY 1985, the test year for designing rates, by using a hydro study that shaped hydro generation to reflect a uniform amount of surplus over the 42-month critical period. This resulted in less hydro generation in the first year than in later years of the critical period.

BPA decided for the final proposal to assume a levelized hydro output over the 42-month period, rather than a levelized surplus. This is an appropriate method for determining hydro capability for the test year in that this assumption provides sufficient energy over the critical period, prudently, to support anticipated long-term sales. Levelizing hydro output will produce more hydro energy in the first year of the critical period than would have been produced by levelizing the surplus. This would be of benefit to Priority Firm purchasers, because the more hydro generation assumed available, the less of the more expensive exchange resources would be assumed to be used to serve their loads.

In the final proposal, as in the initial proposal, BPA uses a 39-month average for determining the average hydro generation over the critical period. BPA plans significantly more generation in May than is necessary to meet projected firm loads because of water budget requirements for the enhancement of stream flows for migrating fish. This excess generation is not included as a firm resource.

BPA also includes the output of Washington Public Power Supply System Project Number 2 (WNP-2) and 50 percent of the output of Hanford as FBS resources in studies for both the initial and final rate proposal. These resources are included because of consideration of their relatively low cost (less than the 7(b) rate), the load uncertainties over the next 10 years, and the opportunity to market the resources at a rate above costs.

Both the magnitude and marketability of surplus firm power are important factors in rate development. The magnitude of the surplus during the test year was increased by the decision to levelize hydro generation over the 42 month critical period, rather than levelize the surplus. As indicated above, this benefits Priority Firm purchasers by increasing the FBS resources available to serve those loads. Levelization of hydro generation likely will increase the total resources available for sale by increasing generation in the first year of the critical period and thereby reducing the likelihood that nonfirm resources will be spilled. BPA has increased it estimate of the amount of surplus firm power that will be sold from the level contained in the initial proposal, but not by as much as the increase of surplus available for sale. Projected surplus sales were increased because the surplus resources available for sale increased and because more interest recently has been shown in purchasing surplus firm power. BPA did not feel that there was sufficient interest to warrant the assumption that all the surplus will be sold.

Conservation program levels used in BPA's initial proposal, as supplemented by supplemental testimony, are $249.5 million for FY 1983, $192 million for FY 1984, and $189 million for FY 1985. Parties raised a number of issues concerning these levels, including the suggestion that conservation program levels be reduced during the near-term period of surplus. The Administrator determined that the program levels are appropriate for the current surplus conditions. An increase in the near-term surplus is an unavoidable consequence if BPA acquires the necessary conservation to achieve the least-cost mix of resources for meeting long-term power needs. BPA's analyses indicate that either decreasing or increasing conservation acquisition would increase system cost in the long run.

Other preliminary issues resolved prior to the development of BPA's revenue, cost, and rate studies concerned BPA's revenue forecast and the classification of costs between demand (capacity) and energy. The revenue forecast assesses BPA's financial position at the beginning of the rate period. After rates are developed it verifies that, based on projected loads, the proposed rates will recover the needed revenues. For FY 1983, the sum of forecasted and actual revenues used to develop the final proposal were less than projected in the initial proposal. This situation was largely a result of adverse economic conditions, warmer than usual weather, and unusually heavy precipitation that caused an excess of resources.

Classification of costs between demand (usage at the times of system peak) and energy (total usage during a time period) was a major area of controversy during the rate filing. This subject was treated as a preliminary issue because it permeated almost every aspect of the rate case. BPA classifies costs between capacity and energy to reflect the differing purposes for which costs were incurred. Various parties claimed that BPA's classification of some fixed costs to energy rather than capacity had an adverse effect on revenue stability and lowered BPA's system load factor. The Administrator found insufficient evidence in the record to support these claims.

BPA uses various methods in its Cost of Service Analysis (COSA) to classify its costs incurred for generation. Hydro costs are classified by a formula using the average energy and peaking capabilities of the hydro system under critical water. Fish and wildlife costs are classified according to the overall hydro capacity/energy ratio. Costs of thermal plants are classified according to the percentages developed in the Time Differentiated Long Run Incremental Cost (TLDRIC) Analysis. The TDLRIC analysis identifies costs incurred to meet future load growth, while the costs used in the COSA are the costs expected to be incurred during the rate period. The TDLRIC analysis supports the view that thermal plants are being built primarily to supply energy, but also will provide capacity. Resource acquisition costs also are classified according to percentages developed in the TDLRIC analysis because they are incremental resources, that is resources being acquired to meet load growth. Costs of BPA's conservation program that are allocated to rates are classified by a formula using the relative levels of energy and capacity savings valued at the long run incremental costs (LRIC) of energy and capacity. This reflects the fact that BPA incurs conservation costs to avoid purchasing more expensive resources. BPA's other costs of generation, deferral, and cash lag are classified according to the classification of FBS, Exchange, and New Resources (NR) generation annual costs and net repayment requirement. Generation costs of the investor-owned utility (IOU) exchange are classified based on a weighted average of FBS and NR classification percentages for generation, because the mix of exchange resources is similar to BPA's mix of hydro and thermal resources. Preference agency exchange costs are classified based on the same percentages as Federal resource costs included in the Priority Firm rate. Consistent with accepted utility practice and with BPA's previous treatment of transmission costs, all transmission costs are classified 100 percent to capacity.

Parties suggested it would be more appropriate to use a single method to classify all generation costs between demand and energy. Criticism also was leveled against some of the specific methodologies used to classify the various types of generation. BPA believes the use of separate methods for classifying the various types of generation costs reflects the diverse nature of BPA's generation expenditures and the diverse reasons for which the costs were incurred. BPA also believes that the methods are theoretically sound and provide a basis for developing accurate and objective cost classification.

In the Wholesale Power Rate Design Study (WPRDS), BPA classifies excess revenues and revenue deficiencies to capacity and energy. Excess revenues are classified according to reverse TDLRIC percentages, and the revenue deficiency resulting from BPA's value of reserves credit to the DSI's is classified according to TDLRIC percentages. The percentages developed in the TDLRIC Analysis are used to bring the results of the COSA classification of embedded costs closer to the relationship of incremental or long run costs of capacity and energy determined in the TDLRIC analysis. The COSA classification process results in a greater percentage of costs classified to capacity than does the TDLRIC analysis. The TDLRIC analysis indicates that although all costs are increasing, the cost of supplying new energy is increasing at a faster rate than the cost of supplying new capacity.

Revenue Requirement Study

After resolving preliminary issues, BPA prepared a Revenue Requirement Study. BPA's statutory obligation is to set rates at a level sufficient to produce revenues that will recover all operating costs and repay the government's investment in power facilities, conservation, and other programs. The Revenue Requirement Study calculates the revenue level required to recover all costs over the repayment life of the facilties or programs and provides the starting point for all other cost and rate design studies.

The Revenue Requirement Study demonstrates that revenue from existing rates is insufficient to fully recover all costs. A number of factors have contributed to BPA's need to increase revenue. A significant portion of the required revenue increase for the rate period is attributable to costs associated with WNP-1, -2, and -3. BPA will be recovering for the first time operating costs for WNP-2, which is scheduled to begin operation in February 1984. As a result of recent developments concerning the Supply System plants, BPA has agreed to fund completion of WNP-2 from its revenues and pay the rampdown and preservation costs associated with BPA's 70 percent share of WNP-3, which has been placed in a minimum preservation state. Exchange costs also have increased primarily because a larger portion of residential and rural loads will be eligible to be served with priority firm power. In addition, revenue collected by BPA in Fiscal Year (FY) 1983 is anticipated to be significantly lower than had been forecasted when the rates for FY 1983 were developed, causing BPA to defer additional interest payments in FY 1983 and placing new demands on BPA's revenue requirement in FY 1984 and FY 1985.

As a means of promoting fiscal integrity, BPA proposed to finance from revenue 5 percent of BPA's construction and conservation program. Although some parties suggested that BPA finance entirely through its borrowing authority, the Administrator believes that the use of revenue to fund 5 percent of BPA's conservation and construction program is consistent with common utility practice and BPA's goal of maintaining fiscal integrity.

The revised Revenue Requirement Study reflects the assumption that BPA will revenue finance the remaining construction costs for WNP-2 and rampdown and preservation costs of WNP-3 when the WNP-3 construction fund is depleted. The decisions to continue the construction of WNP-2 and to ramp down construction and preserve WNP-3 occurred in a forum separate and outside the rate case. Any challenge to the lawfulness of these decisions may only be brought in forums other than this rate case. The issue in this rate case is the revenue requirement associated with continued construction of WNP-2 and rampdown and preservation of WNP-3. BPA believes that the revenue requirement identified in this rate proceeding accurately reflects the costs of these actions.

BPA included in its revenue requirement funding for Columbia River Basin Fish and Wildlife Program measures, but assumed that portions of the program would be funded by sources other than BPA. Parties representing fishery interests urged that all measures be funded by BPA and implementation of some of the measures be accelerated. BPA is not obligated by law to be the sole source of funding for fish and wildlife programs. Moreover, BPA believes the identified program funding levels provide for a reasonable implementation schedule.

Another major area of concern with respect to determining BPA's revenue requirement relates to the calculation of the Residential Exchange and the Exchange Transmission Credit Agreement costs. The Exchange Transmission Credit Agreement (ETCA) gives BPA utility customers not participating in the

Residential Exchange Agreement an opportunity to receive benefits for their transmission systems that they would have received under a Residential Exchange Agreement. BPA developed a methodology to forecast investor-owned utility residential exchange costs that incorporates use of an average annual rate of growth (AARG) factor. The AARG is determined by disaggregating and projecting the major components of each utility's average system cost. This AARG is applied to BPA's estimate of each utility's average system cost in effect or anticipated to be in effect during FY 1983 to project an average system cost for each utility through FY 1985.

BPA submitted supplemental testimony revising the initially proposed projections of average system costs. These revisions were adopted in the final proposal and include use of more current data for estimating base FY 1983 average system costs; exclusion of power cost adjustments from calculation of IOU's FY 1983 average system costs; use of the period FY 1983-FY 1985 rather than FY 1983-FY 1988 to calculate AARG; and revision of costs of new production units used in projecting residential exchange costs.

BPA included Snohomish County PUD as a participant in the residential exchange program rather than the ETCA program because Snohomish potentially could receive greater benefits under the exchange program than the ETCA. In the initial proposal and supplemental testimony, BPA included 17 Pacific Northwest Generating Company members in its forecast of preference agency residential exchange during FY 1984 and FY 1985. Four of the seventeen utilities no longer are members of the Pacific Northwest Generating Company, and therefore BPA has excluded them from forecasts of preference agency exchange costs and exchange loads for the final proposal.

Time-Differentiated Long Run Incremental Cost Analysis

A TDLRIC analysis was prepared to determine the incremental costs BPA incurs on a seasonal, daily, and hourly basis for new generation and transmission load. The analysis identifies the projected costs to be incurred to meet increased customer demand or those costs avoided by customers not demanding additional power. The TDLRIC analysis provides the basis for classification of certain generation costs between capacity and energy and for the seasonal and diurnal differentiation of capacity costs in the COSA as well as certain adjustments in the WPRDS. Application of the illustrative rates developed in the TDLRIC analysis would provide information to consumers that would enable them to make more efficient consumption and investment decisions based on the costs to society of providing electric power.

Although the general use of LRIC principles was questioned during the rate proceedings, BPA believes that by reflecting results of the LRIC analysis in its rates, it can convey information about future costs. Some parties contended during the rate proceeding that TDLRIC rates do not promote engineering or economic efficiency. Nevertheless, the weight of the evidence presented demonstrated that BPA's application of TDLRIC principles promoted engineering and economic efficiency.

Numerous issues were raised concerning BPA's methodology used in the TDLRIC analysis. BPA calculates the LRIC of capacity based on the cost of a combustion turbine and the LRIC of energy on the cost of a baseload coal plant. Each of the generation technologies provides both capacity and energy, and a simultaneous equation solution is used to separate the joint products of capacity and energy. The results of the TDLRIC analysis indicate that 83 percent of the total LRIC of generation is energy related while the remaining 17 percent is capacity related.

The current BPA generation system is not used to project the resources necessary at the margin because BPA does not anticipate a deficit until the 1990's. Although the resources used for the analysis are generic, they represent the lowest-cost sources of capacity and energy available to BPA on a planning basis. Time of day and seasonal differentiation are based solely on actual operation of BPA's current system.

BPA used the same basic TDLRIC methodology in the final proposal as in the initial proposal, including the determination of combustion turbine capacity factor and heat rate, forced outage reserve requirements for the combustion turbine and coal plants, and annual investment, fuel, and operation and maintenance costs. BPA continued to use the 1957-58 water year to plan for capacity needs. BPA also continued to assign no long run energy costs to the month of May, because an increase in energy demand during May would not require additional baseload thermal capability. Although the LRIC of generation-integration was not included in the 1983 initial TDLRIC analysis, it was presented in BPA's rebuttal testimony and included in the final proposal.

Cost of Service Analysis

The Cost of Service Analysis (COSA) determines the cost of providing service to various customer classes and provides a basis for designing rates that will recover from each customer class the costs assigned to it. The analysis consists of the following five basic steps: (1) functionalization or the apportionment of costs between generation and transmission; (2) classification of costs either to capacity or energy; (3) segmentation or apportionment into segments the costs of the Federal Columbia River Transmission System according to the services that facilities in each of those segments provide; (4) seasonal differentiation or assignment of energy and capacity costs to winter or summer periods; and (5) allocation of costs to rate classes.

In the COSA, treatment of energy costs during the month of May reflects seasonal differentiation of energy costs on the basis of monthly withdrawals of stored water, and the results of BPA's TDLRIC analysis that ascribes no incremental costs to energy produced during the month of May. No costs are assigned to May energy. It would be inappropriate to design rates that would distribute energy during the month of May at no charge. May energy costs, therefore, are reassigned to all other months; however, the seasonal periods selected in the COSA are retained. The effect of reassigning May energy costs to all other months and retaining the COSA seasonal pricing periods is to increase the differential in unit costs of energy between the summer period (April through August) and the winter period (September through March).

BPA seasonally differentiates FBS energy costs on the basis of energy produced from withdrawals of stored water in the reservoirs. The method recognizes that the only costs of energy production that vary by season are the costs of producing energy from storage. All resource costs are seasonally differentiated according to percentages developed for FBS costs.

BPA reconciled through rebuttal testimony the difference between the size of the FBS resources used in the COSA, and the size of the FCRPS resources used in the Loads and Resources Study. The COSA excludes hydro generation that serves loads to which no costs are allocated and from which revenues are derived by contractual arrangement. The reconciliation demonstrates that the FBS hydro calculation in the COSA is consistent with the FCRPS hydro calculation in BPA's Loads and Resources Study.

BPA's methodology for allocating conservation costs reflects the relative benefits of conservation to BPA ratepayers and participants in BPA conservation programs. Ratepayers benefit because conservation allows BPA to avoid the purchase of costly new generating resources. Participants benefit because a utility avoids power purchases when the utility or other entity participates in a BPA-funded conservation program. BPA's methodology allocates costs to BPA rates in proportion to the rate benefit. The formula BPA used to determine the portion of costs assigned to BPA rates recognizes that BPA ratepayers benefit from BPA's avoided purchase of the marginal resource to serve BPA loads. The formula also takes into account that the benefit is offset by BPA's lost revenue (at BPA's rate) from not selling the power saved by conservation. After assignment of costs to BPA rates, remaining costs are allocated across total regional energy loads. After conservation costs are divided between the rates and the regional load charge, the costs assigned to BPA rates are allocated to individual rate classes. Conservation costs are not allocated directly to loads served by exchange resources because these loads pay BPA-funded conservation program costs through payment of exchange costs. Conservation costs also are not allocated to the first quartile of the Industrial Firm Power rate because first quartile pricing already includes the conservation costs included in the Nonfirm Energy Standard rate.

Costs associated with the BPA portion of regional loads are allocated to the Priority Firm rate class. Non-BPA loads of participants are assessed a regional load charge through long-term conservation contracts. In developing the contract charge for the final proposal, BPA distinguished between two types of requirements customers with non-BPA load: metered requirements customers and computed requirements customers. Because metered requirements customers with non-BPA load are required to operate their resources in a contractually specified manner, they are considered more similar in operating characteristics to full requirements customers than to computed requirements customers. Therefore, the contract charge asessed non-BPA loads of metered requirements customers is the same as the regional load charge paid through the Priority Firm rate. In the final proposal, the contract charge assessed computed requirements customers is a two-part charge based on a regional load charge and a reimbursement charge to reflect the level of the utility's participation in BPA conservation programs. By dividing the conservation charge between the load charge and reimbursement charge, BPA ensures recovery of fixed program development costs and also allows computed requirements customers control over part of the charge.

The allocation of capacity costs addresses the fact that machine capability of Federal resources exceeds loads, including potential surplus power loads, expected to be served by Federal resources. Exchange resources are defined to be equal to exchange loads. Therefore, BPA has determined that only Federal resource pools (i.e. the FBS and new resources (NR) pools) contribute to the existence of excess peaking capability identified in BPA's capacity load and resource comparisons. BPA brought capacity loads and resources into balance by scaling the size of only the Federal (FBS and NR) resource pools. This process attributes the cost of excess capacity to the resource pools in which the excess capacity originates. While the exchange resource pool makes no contribution to excess peaking capability on BPA's system, the costs of excess capacity associated with exchange resources are included in the Average System Cost that BPA pays for exchange resources. Once capacity loads and resources are balanced by use of the scaling process described above, resource pool capacity costs are allocated to rate pools in a manner identical to the allocation of energy costs.

BPA allocates fish and wildlife costs only to firm power customers that are allocated the costs of FBS resources. Costs incurred to mitigate the damage to fish and wildlife caused by Federal dams are charged only to assured beneficiaries of the output of these dams.

The COSA load/resource balance includes the loads and resources of exchanging utilities that are projected during the test year to be "deemed equal" pursuant to section 10 of the Residential Purchase and Sale Agreement. Exchanging utilities may deem equal when their average system cost is less than BPA's Priority Firm rate. The loads and resources are included in the COSA load/resource balance because the exchanging utilities accrue the liability to BPA for "negative" exchange benefits while in the deemed equal status. The exchange transaction is still operative, and the account must be brought into balance before the utility can resume receiving the monetary benefit of the exchange.

BPA allocates costs associated with deferred payments to the U. S. Treasury to all customers on the basis of loads. BPA has no basis for making a customer-specific allocation of deferral costs. Costs associated with the deferral relate to BPA's underrecovery of costs in the past. Except where required by statute, BPA does not hold specific customers or customer groups accountable for past cost overrecoveries or underrecoveries resulting because forecasted costs or loads in past rate filings differed from actual costs or loads.

Wholesale Power Rate Design Study

The Wholesale Power Rate Design Study (WPRDS) is the final step in the development of BPA's wholesale power rates. In this study, allocated costs from the COSA are modified to reflect BPA's rate design objectives, to conform with contractual requirements, to reflect the results of other BPA studies, and to conform with applicable legislation. The modified costs are then divided by the applicable billing determinants to determine BPA's wholesale power rates.

Adjustments

BPA makes a number of adjustments to the results of the COSA to derive the final wholesale power rates. These adjustments include treatment of: (1) revenues generated in excess of costs, (2) fixed contract revenue deficiencies, (3) the value of reserves credit, (4) the surplus firm power revenue deficiency, (5) equalization of demand, and (6) the Hanna discount. Major issues associated with specific adjustments are discussed below.

During the rate proceedings, the appropriateness of assigning fixed contract revenue deficiencies only to the FBS loads was questioned. The Administrator, however, decided that in the final proposal, as in the initial proposal, fixed contract revenue deficiencies should be allocated to FBS users because these contracts enhance the capability of the FBS.

Another issue raised concerned the determination and application of the credit granted to the DSI's for the reserves they provide BPA by allowing BPA to restrict their loads. BPA bases the credit on a share-the-savings concept that shares risks and benefits of providing restriction rights between interruptible DSI load and the other firm power customers. The revenue deficiency resulting from the value of reserves credit was allocated to all firm loads in the initial proposal. In the final proposal, the reserves are allocated to all firm loads served by FBS and New Resources, because these resources receive the protection the reserves provide. Exchange resources are not allocated the revenue deficiency because BPA reserves are not needed for exchange resources.

The allocation of the Surplus Firm Power revenue deficiency is another important issue. BPA is not expected to sell all of its Surplus Firm Power at the Surplus Firm Power rate, but will have to sell a portion at the lower Nonfirm Energy rate. First the revenue deficiency is prorated among the components of surplus power costs. These include exchange resources, new resources and an adder (transmission and overhead). Revenue deficiencies attributable to the exchange resource cost component are allocated to the Industrial Firm Power class. New resource and adder revenue deficiencies are allocated to all firm sales.

Changes and Adjustments Applying to More Than One Rate Schedule

BPA has included in its firm power rate schedules an 83 mill/kWh unauthorized increase charge for power taken during peak hours at rates of delivery beyond contractual limits and/or energy taken above prescheduled kilowatthour totals. The unauthorized increase charge is not an average-cost based charge for a service offered by BPA. Instead, it reflects the highest costs that BPA may incur, the 83 mill/kWh running costs of a single-cycle combustion turbine.

BPA's computed requirements customers have their own generation and considerable contractual flexibility in the use of their resources. Displacement of firm purchases from BPA by computed requirements purchasers recently has resulted in significant revenue underruns, especially as a percentage of the forecast revenues from that class. To help mitigate future revenue shortfalls attributable to these customers, BPA's initial proposal included an availability charge in the billing factors for computed requirements customers. Some parties argued that the computed requirements customers were no more responsible for BPA's revenue shortfall than other customers. BPA decided that it would accept the risk of retail load swings from all its utility customers because those variations are outside the utility's control. BPA is not willing, however, to accept all the risk for variations caused by displacement of firm purchases with a utility's own nonfirm or with nonfirm purchases. Therefore, in the final proposal, BPA included an availability charge in the billing factor for all computed requirements customers.

BPA has included two adjustment clauses that automatically adjust rates in response to changes in the actual costs of major expense items over which BPA has little control. The first is an Exchange Adjustment Clause (EAC). It is included in the Priority Firm, Industrial Firm, Firm Capacity, and New Resource firm rates because exchange resources are assigned to loads served under these rates. In the initial proposal the adjustment, which is also included in current rates, is in the form of a rebate or surcharge applicable if the actual average cost of exchange resources during the rate period differs from the forecast of that cost. In the initial proposal, BPA based the EAC on the average system costs of the non-deeming IOU's because they represent the major portion of net costs of the exchange. For the final proposal, the EAC was redesigned to track changes in the net cost of the exchange on BPA. Thus, it varies with both exchange loads and costs. BPA proposed initially that the adjustment could be made either monthly or twice during the 20-month rate period. BPA eliminated the monthly option for the final proposal because under the reformulated EAC, the monthly adjustment would be far more complicated and variable.

The second adjustment, a Supply System Adjustment Clause (SSAC), is included in the Priority Firm Power and Firm Capacity rate schedules to adjust for changes in the cost of Supply System plants WNP-1, -2, and -3. The adjustment will be made to the Priority Firm energy charge and the Firm Capacity rate effective July 1, 1984, if the actual OY 1984 Supply System net funding requirement or the OY 1985 Supply System Annual Budget for WNP-1, -2, and -3 differs from the costs included in the revenue requirement for those years. BPA has limited the cost changes included in the SSAC to cost increases necessary to maintain the plant construction status assumed for the 1983 rate filing. Concern has been expressed that if construction debt financing is found, total Supply System costs could go up, but the SSAC would lead to a reduction in BPA's rates. The language in the final proposed SSAC has been modified to ensure that BPA will not lower rates if total Supply System construction costs increase. The language in the SSAC also has been clarified to include cost changes associated with repayment of funds loaned to BPA or an organization other than the Supply System for construction of WNP-1, -2, and -3. A formal comment process, including a reasonable opportunity for cross-examination of witnesses, will be provided prior to implementation of a Supply System adjustment.

The rate period for the 1983 rate case is 20 months. In the initial proposal, BPA proposed that the 20-month period be separated into two periods, each with separate charges. BPA discovered that the methodology used in the initial proposal for determining rate period revenue requirement would not recover the FY 1984 revenue requirement. For the final proposal, BPA developed a single set of rates, based on cost allocations for OY 1985, applicable to the entire 20-month period to recover the revenue requirement for the 20-month period.

Although the LRIC Analysis suggested the existence of a shoulder capacity period, BPA is not including a shoulder period in its proposed rates. BPA does not have data to determine coincidental and noncoincidental demand on a daily or hourly basis and does not know the extent to which utilities would shift loads to the shoulder period. Consideration of rate continuity and ease of administration also are factors in BPA's decision not to implement the shoulder capacity period.

Wholesale Power Rate Schedules

The wholesale power rate proposal includes the following 11 rate schedules: Priority Firm Power, PF-83; Industrial Firm Power, IP-83; Industrial Hanna, IH-83; Firm Capacity, CF-83; Emergency Capacity, CE-83; New Resource Firm Power, NR-83; Surplus Firm Power, SP-83; Surplus Firm Energy, SE-83; Nonfirm Energy, NF-83; Energy Broker, EB-83; and Reserve Power, RP-83. The major issues associated with specific rate schedules are discussed below.

Priority Firm Power Rate, PF-83

The PF-83 rate is applied to BPA's sales of firm power to public bodies, cooperatives, and Federal agencies, as well as utilities participating in the residential exchange authorized by the Regional Act.

A Low Density Discount is included in the Priority Firm Power rate, as authorized by the Regional Act, to alleviate adverse impacts of wholesale rates on retail rates of customers with low system densities. In determining a utility's eligibility for the discount, BPA considers the ratio of residential consumers to the number of pole-miles of distribution line, as well as the ratio of total kilowatthour sales to investment costs. The kilowatthour-to-investment ratio was implemented to screen out utilities that have many kilowatthours over which investment costs can be spread and therefore are not typical of utilities with low system densities. All customers purchasing power under the Priority Firm rate, including publicly owned and investor-owned utilities purchasing exchange power under the rate, are eligible for the discount if their systems meet the eligibility criteria. Because Priority Firm customers are the beneficiaries of the Low Density Discount, costs of the discount are assigned to the Priority Firm class.

During the rate proceeding, parties representing irrigation interests proposed that BPA adopt a seasonal irrigation rate. BPA did not include an irrigation rate in the final proposal because BPA believes that it is not appropriate to single out irrigators for rate relief. Such relief is not mandated in the Regional Act. Furthermore, irrigators have not demonstrated that a special irrigation rate would provide tangible benefits to the BPA system. It is also questionable whether an irrigation rate would be consistent with BPA's conservation efforts or statutory mandate that rates be "consistent with sound business principles."

BPA's proposed rates contain features that provide substantial benefits to irrigators. Seasonal differentiation of demand and energy charges benefits summer loads. Irrigators also can concentrate use during Sunday and nighttime hours when there are no demand charges in effect. Modifications to the seasonal differentiation for the 1983 proposal provide even greater benefits to irrigators. These include: (1) moving the month of May from the winter to the lower summer capacity season, and (2) assigning no energy costs to the month of May, resulting in lower summer energy rates.

BPA found insufficient evidence on the record to support inclusion of a separate charge for transformation in its Priority Firm rate. BPA also found insufficient support for the development of a separate rate for customers with pre-Act power sales contracts.

Industrial Firm Power Rate, IP-83

The IP-83 rate is available to BPA's existing DSI's and reflects a credit for the system reserves the DSI's provide. BPA prepared a value of reserves analysis to assess the value to BPA of the reserves provided by BPA's ability to restrict DSI loads. During the rate proceeding, the value of the DSI reserves during a surplus period was questioned. BPA believes that because BPA acquired the reserves from the DSI's through long-term contracts, the obligation to provide compensation for their reserves is the same as if BPA had constructed actual generation facilities to provide reserves. If BPA had constructed facilities to provide reserves, the capital costs of the resources would be included in BPA's revenue requirement even if the reserves were not used. In valuing the reserves, BPA did consider that reduced plant operating costs would occur if resources were not used because of surplus conditions.

BPA segmented the Federal system reserves into forced-outage reserves, stability reserves, and plant delay reserves. The value of forced-outage reserves is based on the costs of combined cycle combustion turbines. The value of the stability reserves is based on the investment cost of a region-wide load-tripping scheme. In valuing plant delay reserves, BPA used the Pacific Northwest System Analysis Model to determine the probability of expected outages because of delay and unexpected poor performance of Federal plants.

The DSI's recently have contributed significantly to BPA's revenue instabilty because their loads have underrun their forecasted loads. To enchance revenue stability, BPA is including a customer charge in the proposed IP-83 rate in addition to the demand and energy charges. In the initial proposal, BPA based the customer charge on operating demand. Operating demand is the negotiated estimate of the power the DSI's will purchase from BPA. The customer charge in the final proposal has been modified and will be based on the greater of actual operating level or on 89.4 percent of the operating demand forecast in the rate proceeding. The 89.4 percent represents the ratio of costs allocated to the lower three quartiles to total costs allocated to the DSI's. This modification allows for DSI loads to vary without penalty to the extent those variations do not cause BPA to lose firm power revenues. The customer charge has been designed to collect the difference between the costs allocated to the lower three quartiles and the revenue that would be collected from applying the Priority Firm rate to that level of usage. BPA proposed initially that the customer charge be applied even if the DSI load were restricted or curtailed. For the final proposal, BPA decided that the customer charge should not apply to restricted load.

BPA does not plan or acquire resources to serve the first quartile of industrial load. The first quartile is served by: (1) a combination of provisional drafts and nonfirm energy, or (2) surplus firm energy load-carrying capability. The IP-83 rate schedule includes two sets of rates. One rate, the Standard rate, is available for customers selecting first-quartile service with provisional drafts and nonfirm energy. The other rate, the Premium rate, applies to customers requesting first-quartile service with surplus FELCC.

In the initial proposal, BPA forecasted approximately 76 percent service to the first quartile based on an analysis of 40 water years. For the final proposal, BPA continued to base the forecast of service to the first quartile on an analysis of 40 water years. However, it also is assumed that the first quartile represents a potential market for surplus firm power. This results in a much higher forecast of service to the first quartile.

BPA does not plan resources to serve the first quartile on a firm basis, so no costs other than transmission are allocated to the first quartile in the COSA. In the WPRDS, BPA assigns a price to the first quartile when served with nonfirm energy and provisional drafts that is based on opportunity costs or the revenue BPA could have received if the energy had been sold in alternative markets. For the initial proposal, the opportunity cost associated with serving the first quartile was approximated by pricing service with Nonfirm Energy at the generation portion of the monthly average Nonfirm Energy rate and by pricing service with provisional drafts at the generation portion of the Nonfirm Spill rate. For the final proposal, service to the first quartile with Nonfirm Energy and provisional drafts is priced at the generation component of the annual average Nonfirm Energy rate.

The cost assigned to the first quartile when served with surplus FELCC is the same unit cost as the lower three quartiles, representing BPA's cost of serving the industrial load with firm exchange resources. Service with surplus FELCC is considered a different kind of service than service with provisional drafts or nonfirm energy and is therefore priced accordingly.

For the final proposal, a provision has been included in the IP-83 rate to offer the DSI's a special incentive rate to operate at a higher level during the rate period if such a rate is forecasted to increase BPA's revenues. The incentive rate will be set at a level that maximizes BPA revenues. If the revenue-maximizing rate is lower than the IP-83 Standard rate, the revenue-maximizing rate will be offered for a period of not less than 6 months and not more than a year.

BPA has continued to assume for the final proposal that the nonfirm sales to the DSI's will end as of November 1, 1983. No special rate has been included for such sales, nor have any steps been taken to preclude them. The decision as to whether these sales will continue will be made outside the rate process.

Industrial Hanna Rate, IH-83

Consistent with provisions of the Regional Act, a special rate has been established for Hanna Nickel Smelting Company to enable Hanna to avoid adverse impacts from increased rates. In the initial proposal, BPA set the IH-83 rate equal to the PF-83 rate, less the value of reserve credit. BPA is including this rate in the final proposal and also is including an additional special rate of 7 mills per kilowatthour, with no demand charge, that would be applicable under specified times and conditions. Hanna proposed the special rate during the rate filing, claiming it would enable Hanna operations to be resumed shortly after November 1, 1983. The 7-mill rate will be eliminated when Hanna requests more than 10 percent of contract demand during the peak period. At that point the standard IH-83 rate would apply to all purchases.

Firm Capacity Rate, CF-83

The CF-83 rate schedule applies to contract purchases of firm capacity on a yearly, seasonal, or general basis. To encourage capacity purchasers to limit their use of Federal generating facilities and maximize use of their own facilities, the CF-83 rate includes an additional monthly charge for capacity taken in excess of 9 hours during BPA's peak period. The charge is cost-based and reflects additional costs incurred by BPA because the Federal hydro system cannot generate as much capacity during sustained daily periods as it can for shorter periods and because of occasional problems caused by the return of energy at night.

BPA has included a separate rate for Intertie service in the CF-83 rate. The Intertie adder is calculated based on the difference in unit costs between the Intertie costs and the portions of the equalized demand charge attributable to Pacific Northwest fringe and delivery facilties.

Firm Energy Rate

BPA has eliminated the Firm Energy rate schedule and replaced it with the PF and NR rate schedules, which provide basically the same quality of service as the Firm Energy rate schedule.

New Resource Firm Power Rate, NR-83

The NR-83 rate schedule applies to IOU load growth and new large single loads of BPA's preference agency customers. No capacity costs were allocated in the COSA to serve this load. However, BPA believes the rate should be designed so it can be applied to any load that qualifies for NR-83 service. Therefore, the rate includes an energy charge and a demand charge set equal to the equalized PF demand charge.

Surplus Firm Power Rate, SP-83

Surplus firm power will be sold under four different rates: a fixed Contract rate and three variable rates. The variable rates are: a Thermal Resource rate, an Exchange Resource rate, and a Purchased Power rate. The three variable rates are offered to provide BPA with marketing flexibility. Short-term sales may be made at any of the four rates. Long-term sales would be made under the Contract Rate, which is based on the fully allocated cost of surplus resources; i.e., exchange resources and new resources.

Beginning July 1, 1985, an escalation factor will be applied to the Contract rate on a yearly basis to account for changes in the cost of exchange resources. BPA is offering two escalator options: a fixed escalator and an escalator dependent on the actual percentage increase in the average cost of the selected exchange resources in the prior year. Although the Contract rate was seasonally differentiated in the initial proposal, seasonal differentiation is eliminated in the final proposal to improve the marketability of the surplus.

Nonfirm Energy Rate, NF-83

The NF-83 rate applies to purchases of nonfirm energy both inside and outside the Pacific Northwest. The rate schedule includes a contract rate and four market rates: the Standard rate, the Spill rate, the Displacement rate, and the Incremental rate.

The initially proposed NF-83 rate contained a guaranteed delivery provision similar to the one included in the NF-2 rate implemented in 1982. BPA proposed initially to guarantee delivery of one-half of the daily amounts of energy offered for sale under the Standard rate. BPA revised the conditions of the guarantee for the final proposal in response to comments and suggestions from parties representing California utility interests. BPA now is proposing to indicate on the first working day of each week the daily (and, if necessary, the hourly) amount it is willing to guarantee through at least the coming Friday. On the last working day of each week, BPA will indicate the amount it is willing to guarantee through at least the coming Tuesday. BPA may make such indications more often if BPA determines that it is appropriate.

Guaranteed delivery may be offered for energy sold at the Standard rate, Spill rate, Displacement rate, or Contract rate. Once requested, the guaranteed energy will be provided on a take-or-pay basis. An additional charge of 1.8 mills/kWh will be assessed for guaranteed delivery, with the exception of the guaranteed delivery of Displacement rate energy for nuclear plants. The charge equals the average thermal resources capacity costs and will compensate BPA for the additional risk undertaken by guaranteeing service.

The Standard rate is based on the average cost of the FBS and New Resource pools, plus the average cost of transmitting such power. Sales and revenue from all below-cost NF-83 and EB-83 rates are excluded from the calculation. Thermal resource capacity costs also are removed from the nonguaranteed Standard rate.

A Displacement rate was not included in the NF-2 rate schedule. In the initially proposed NF-83 rate, the Displacement rate was a share-the-savings rate, effective when BPA had more energy than could be sold at the Spill rate. The Displacement rate in the final proposal includes two fixed rates to allow BPA to displace: (1) coal-fired resources and end-user alternate fuel loads, and (2) nuclear generation. Fixed rates were chosen to facilitate administration of the rate schedule. The availability criteria also were changed to allow the Displacement rate to be offered in spill or forecast spill conditions, regardless of whether the Spill rate has been implemented. The Displacement rate will be available to displace resources with incremental costs less than or equal to the sum of either the Standard or Spill rate (whichever is in effect) plus 2 mills/kWh. Displacement rate energy also will be available for fuel displacement in dual-fuel boilers. The Standard rate or Spill rate will be applicable to purchases displacing oil and gas-fired generation.

In the initial proposal, BPA suggested that elimination of the Spill rate seriously be considered and presented evidence that this alternative would increase revenues from BPA sales. However, this idea was not adopted in the final proposal because of uncertainty in modeling the nonfirm energy market without a Spill rate. The criteria for implementaing the Spill rate have been changed so that as a spill condition approaches, rather than losing money by immediately implementing the below-cost Spill rate, BPA will use the Displacement rate to displace resources with decremental costs too low to displace at the Standard rate. The Spill rate will be implemented only if such action will increase BPA's revenues or result in more thermal displacement. The Spill rate in the final proposal is reduced from the level suggested in the initial proposal to ensure that BPA is able to widen its market for Spill rate sales.

Transmission Rate Design Study

The Transmission Rate Design Study describes the development of BPA's proposed transmission rates. These rates include: Integration of Resources (IR-83), applicable to the wheeling of firm power within the Pacific Northwest using the Federal system; the Southern Intertie (IS-83), Northern Intertie (IN-83), and Eastern Intertie (IE-83) rates applicable to all transactions on those interties, unless other rates are specified by existing contracts; Energy Transmission (ET-83), applicable to transmission of nonfirm energy on intraregional Federal Columbia River Transmission System (FCRTS) facilities, excluding interties; Use of Facilities (UFT-83), applicable to wheeling transactions over specified transmission facilities, such as radial lines or facilities; Formula Power Transmission (FPT-83), applicable to existing contracts that incorporate it for the transmission of firm power over the Network portion of the Federal system; and the Townsend-Garrison Transmission (TGT-1) rate, a contractually specified rate that applies to the firm transmission of electric power over transmission facilities of BPA's section of the Eastern Intertie.

BPA's IR-83 rate design uses both demand and energy billing factors for firm transmission. This was criticized by parties who felt it would lead to unpredictable revenues and revenue instability. The energy/capacity billing feature was retained for the final rate in order to help achieve BPA's objective of cost distribution which would shift costs from low to high load factor users. BPA's data do not indicate a significant fluctuation in wheeling energy loads that would present a risk of revenue underrecovery.

Issues also were raised concerning the methodology for developing the IS-83 rate. Although alternative methodologies were suggested, BPA adopted for the final proposal the methodology used in the initial proposal. This methodology bases the rate on the average cost of firm wheeling transactions on the Southern Intertie. The resulting rate is well within the range of cost-based and commercially defensible rates for Southern Intertie wheeling.

Two new segments of the transmission system were identified for the 1983 rate filing. These two segments are the Eastern Intertie and the Northern Intertie. The Eastern Intertie includes two 500-kV lines from Garrison to

Townsend and associated terminal and transformer facilities. The Canadian or Northern Intertie consists of existing lines between Custer substation and the border, one of the two 500-kV lines between Custer and Monroe substations, two 230-kV lines between Boundary substation and the border, and the associated substation facilities. The lines associated with the Northern Intertie were not distinguished from the Network in the 1981 rate filing. Although the appropriateness of including certain facilities in the intertie segment was challenged, BPA believes that the proposed segmentation is reasonable. There also was a question as to the amounts of potential billable energy subject to the rate. Specific concern was raised about the inclusion of deliveries of obligation energy for the accounts of California utilities. It was shown, however, that these deliveries are not a part of the energy load to which the rate will be applied.

One of the issues that arose with respect to BPA's transmission rates concerned whether the levels of the FPT rate components should be constrained so that total projected FPT revenues would match the COSA revenue requirement for non-Federal power. The method used in BPA's COSA to allocate costs to non-Federal power using the FCRTS is different from the method specified in FPT contracts. In the initial proposal, BPA used the method specified in the contracts. For the final proposal, the FPT rates were set such that FPT revenues would match the COSA revenue requirement.

BPA indicated in the initial Transmission Rate Design Study that it was considering incorporating the nonfirm revenue loss associated with wheeling non-Federal power over the Southern Intertie into a rate for the use of the Southern Intertie. When BPA allows other utilities to use its portion of the intertie, BPA has less intertie capability to market its own nonfirm power. Federal power may have to be spilled as a result and revenue reduced. Although BPA remains concerned about these revenue losses, a rate to compensate for these losses is not included in the final proposal. BPA believes that the issue needs further study and anticipates that the imminent development of intertie access policy may reveal other solutions.

Analysis of Environmental Impacts

BPA prepared a Draft and Final Environmental Impact Statement (EIS) on its wholesale power rate proposal to comply with requirements of the National Environmental Policy Act. The EIS examines revenue level and rate design alternatives including those representing the upper and lower limits of potential environmental impacts. Significant attention is focused on impacts of BPA wholesale rates on DSI customers and irrigation customers of retail utilities.

Of the revenue and rate alternatives considered in the EIS, BPA believes the proposed alternatives represent the most reasonable choices. The EIS indicates that the proposed increase in BPA rates could have short-term effects on low-income consumers, irrigated agriculture, and BPA's DSI customers. Certain aspects of the proposed rate design, as well as BPA conservation programs, will partially mitigate these impacts. The proposed rate design would not cause environmental impacts significantly different from those experienced under BPA's current rate design.

BPA included several additions to the environmental analysis in the Final EIS to reflect issues identified after publication of the Draft EIS. The Final EIS includes additional analyses of wholesale rate impacts on industrial customers of public utilities, impacts of various new revenue level and rate-design alternatives, and effects of proposed rates on BPA power marketing to the Pacific Southwest.

BPA also prepared an Environmental Assessment (EA) addressing the 1983 transmission rate proposal. The EA considers the effect that BPA's transmission rate proposal might have on the demand for power and on the construction of parallel transmission lines. The analysis concludes that the proposed rate increases are small enough to have no significant effect on the construction, operation, and maintenance of generation facilities and would not provide BPA's wheeling customers with an incentive to build parallel transmission facilities.

Comments of Participants

Public comments on BPA's Wholesale and Transmission Rate proposals were addressed in a separate chapter of the Administrator's Record of Decision. BPA procedures designate as participants either interested individuals or groups who wish to participate in the development of BPA's rate proposals without incurring the obligations placed on parties.

The participants' portion of the Official Record consists of the transcripts of 15 field hearings held from April 11 through April 21, and on July 20 and 21, 1983, at which 219 people commented. BPA also received 2,091 letters and petitions, and 21 telephone calls by July 29, 1983, the close of the comment period.

Based on review of this portion of the record, 17 topics were identified for evaluation that reflect the general concerns expressed by the participants. These topics were: questions as to the need for the increase, suggestions that BPA defer any increase until economic conditions improve, questions concerning inclusion of the Supply System costs in BPA rates, comments urging that BPA not increase the rates to its direct service industrial customers, comments advocating and criticizing continued funding of conservation programs, questions and suggestions as to the pricing of nonfirm energy, comments urging special rate assistance for the poor and retired persons, comments urging special rate assistance for farmers who irrigate, suggestions advocating tiered rates, comments suggesting BPA not increase the demand component of its rates, comments questioning the effects of public participation, suggestions as to BPA funding of fish and wildlife programs, a comment on including a value of reserve credit in the rate for the DSI's, a comment urging provision of a public counsel, a comment advocating elimination of the Supply System Adjustment Clause, questions concerning the seasonal differentiation of BPA rates, and a comment concerning BPA treatment of the Northern Intertie in its transmission rate proposal. From these comments it appears that the participants are most concerned about the rate increase to BPA's direct service industrial customers, whether a rate increase is necessary, the inclusion of Supply System costs in BPA rates, the need for a special rate for irrigators, and the BPA rate for and sales of nonfirm energy. While BPA is unable to satisfy all concerns in the development of its rates, these concerns were considered throughout the decisionmaking process.

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