1982 FINAL WHOLESALE RATE PROPOSAL

EXECUTIVE SUMMARY
OF
ADMINISTRATOR'S RECORD
OF
DECISION

BPA

BONNEVILLE POWER ADMINISTRATION
U. S. DEPARTMENT OF ENERGY

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Executive Summary

Record of Decision of the Bonneville Power Administrator 1982 Wholesale Rate Proposal

Introduction

The Administrator's Record of Decision traces the decisionmaking process that the Administrator of the Bonneville Power Administration (BPA) employed in overseeing development of BPA's proposed 1982 Wholesale Power Rate Schedules. BPA finds it necessary to increase its wholesale rates in order to meet its financial obligations. BPA is submitting the proposed rates to the Federal Energy Regulatory Commission (FERC) for final confirmation and approval and is asking FERC to approve the rates on an interim basis so they may become effective October 1, 1982.

The final rate proposal is based on a number of studies prepared by BPA and described in this document. Comments and testimony received throughout the ratemaking process influenced development of these studies as well as the final rate proposal. The attached flow diagram schematically presents the function of the inputs to the rate development process.

BPA published in the Federal Register a "Notice of Intent to Develop Revised Wholesale Power Rates" (46 FR 50838) on October 12, 1981, and a "Notice of Proposed Wholesale Power Rate Adjustment" (47 FR 13710) on March 31, 1982. The hearings required by the Regional Act began April 12, 1982, and closed July 2, 1982. During the hearings the Inter-Company Pool, Public Power Council, and direct-service industries submitted a joint customer proposal (JCP) that addressed load forecast, resource acquisition, repayment, and revenue requirement issues.

In addition to the formal hearing process, BPA sought to provide for substantial public participation in revising the rates. Eight field hearings were held in April 1982 to allow the public to comment on the initial proposal, and seven field hearings were scheduled in June 1982 to solicit public comment on the hearings record. BPA also received telephone calls and letters commenting on the rate proposal. The extensive record developed formed the basis from which the staff prepared the Staff Evaluation of Official Record, published on July 9, 1982.

The initial Repayment Study prepared by BPA indicated that BPA needed revenues of $2.4 billion in FY 1983 to meet its financial obligations. Following the close of the hearings, BPA completed a final Repayment Study that identified the need for revenues of $2.2 billion in FY 1983. This is an increase of $814.5 million over the $1.4 billion that would be collected in FY 1983 under existing rates. The average rate increase, based on FY 1981 loads, to various classes of customers that now purchase power from BPA is shown below. Because the surplus firm and surplus energy rates are new, an average rate is shown for these loads rather than a percentage increase.

Customer	Average Percentage Increase
Priority Firm	
Municipalities	60
Public Utility Districts (with Low Density Discount)	60
Cooperatives (with Low Density Discount)	59
Federal Agencies	60
Private Utility Residential and Small Farm Exchange Load	60
Industrial Firm	50
Firm Capacity	
Annual	44
Seasonal	13
New Resources	(5)
Nonfirm	19
	Average Rate (Mills/kWh)
Surplus Firm Power	32.2
Surplus Firm Energy	28.4

Legal Requirements

The following is a summary of the statutory requirements governing BPA's rates, revenue requirements, and rate development process.

General Rate Guidelines

The Federal Columbia River Transmission System Act (Transmission System Act), the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), the Bonneville Project Act, and the Pacific Northwest Regional Preference Act all provide general rate guidelines. Section 9 of the Transmission System Act provides that BPA rate schedules will be fixed with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. Section 6 of the Bonneville Project Act provides that rate schedules should be designed to extend benefits of the integrated transmission system and encourage the widest possible diversified use of electric energy. Finally, Section 7 of the Regional Act states that rates will be established and revised to recover, consistent with sound business principles, the costs associated with acquisition, conservation, and transmission of electric power. These costs include amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs to be paid out of power revenues) over a reasonable period of years and other costs incurred by the Administrator as a result of the Regional Act and other laws.

Other statutory provisions address BPA's repayment criteria, the equitable recovery of the costs of the transmission system, and equitable sharing of benefits within and outside the region.

Regional Act Rate Pools

Section 7 of the Regional Act establishes three rate pools. Section 7(b) provides that rates for public body, cooperative, and Federal agency customers within the region and for loads served under the residential exchange (Section 5(c)) will recover the cost of the portion of Federal base system (FBS) resources needed to serve these loads. When these loads exceed the FBS resources, these rates are to be designed to recover the cost of additional power needed to serve the loads, first from power acquired by the Administrator through the exchange (Section 5(c)) and then from other resources.

Rates for BPA's direct-service industrial customers (DSI) are governed by Section 7(c) of the Regional Act. Section 7(c) states that DSI rates prior to July 1, 1985, are to recover the cost of resources the Administrator determines are required to serve these customers' loads. Additionally, the net costs incurred by the Administrator under Section 5(c) are to be recovered from the DSI's to the extent these costs are not recovered through rates applicable to other customers. The DSI's rates are to be adjusted to take into account the value of power system reserves made available to the Administrator.

Section 7(f) provides that rates for all other firm power sales in the Pacific Northwest will be based on the cost of portions of the FBS resources, purchases of power under Section 5(c), and additional resources the Administrator determines are applicable to these sales.

Confirmation and Approval

Section 7(a)(2) of the Regional Act provides that BPA rates will become effective upon confirmation and approval by FERC. Section 7(i)(6) provides that FERC has authority to approve the final rates submitted by the Administrator on an interim basis pending FERC's final decision.

Preliminary Issues - Loads and Resources

Before BPA can determine its costs and therefore the level of revenues needed, it must determine what the load will be and what resources are available to meet that load.

Load Issues

The initial step in BPA's rate development process is to forecast the loads to be placed on BPA by its customer groups. Because of the complex nature of forecasting and the importance of loads to the determination of costs and ultimately rates, BPA's load forecasts were carefully scrutinized during the rate hearings.

BPA's load forecasts for both peak and energy consist of the following individual forecasts: (1) BPA utility-type loads (forecast of nongenerating and small generating public agency loads as well as contracted Federal agency loads and United States Bureau of Reclamation (USBR) "reserved energy" requirements); (2) direct-service industrial loads; (3) investor-owned utility (IOU) net requirements; (4) generating public agency firm transfers; and (5) residential exchange loads.

BPA traditionally has forecasted BPA utility-type loads by using a sum-of-the-parts methodology consisting of a sum of the monthly estimates for nongenerating and small utility forecasted loads, BPA contracted Federal loads, and USBR "reserved energy" requirements. Because recent comparisions of actual to forecasted loads have found that the sum-of-the-parts methodology has not produced reliable load projections, BPA employed a time series analysis (ARIMA) for the 1982 rate filing in an effort to improve the forecast of BPA utility-type loads.

Parties criticized BPA for not using more recent data in its initial forecast of BPA utility-type loads. The forecast was revised for the final proposal to reflect more recent economic data than either the initial forecast or any forecast suggested by the parties.

The JCP expressed concern that BPA's forecast of BPA utility-type loads did not explicitly account for price and economic effects and urged that BPA use the JCP forecast. The Administator questioned the adequacy of such a forecast and the feasibility of preparing it. BPA did develop a simplified econometric equation similar in structure to that proposed by the JCP to verify the final ARIMA forecast.

BPA's initial DSI forecast was based on operating demands specified by the DSI's in September 1981. However, in light of current economic conditions and reduced loads anticipated by some of the DSI's, the Administrator decided that the total DSI load projections should be reduced in the final proposal.

BPA's initial forecast of IOU net requirements was based on data provided by the IOU's. Subsequently, the IOU's told BPA not to assume that any IOU net requirements would be placed on BPA during the test year because of uncertainties associated with the IOU contracts and the structure of the BPA's NR-2 rate. Therefore, the Administrator assumed that no IOU net requirements will be placed on BPA during the rate period.

The initial forecast of generating public agency firm transfers was based on information from the Northwest Power Pool (NWPP) and the Pacific Northwest Utilities Conference Committee (PNUCC). This forecast was updated for the final proposal to reflect recent information received from the NWPP and PNUCC.

BPA lowered its initial projection of IOU exchange loads for the final proposal to reflect more recent information about the anticipated loads. Although the initial proposal assumed a public agency exchange load, the Administrator decided the load should not be included in the final proposal.

This decision was based on the belief that BPA will offer public agencies Transmission Service Agreements in FY 1983 which will provide those public agencies having transmission facilities with the net benefit they would have received if they had participated in the exchange.

Resource Issues

After the load forecast is developed, the resources necessary to meet that load are identified. These resources include Federal hydroelectric resources, firm purchases, and other available resources. For the initial proposal, BPA ran a series of hydroelectric power planning studies or "hydro regulations" to provide estimates of Federal firm and nonfirm power.

For the final rate proposal, numerous changes were made in the studies. These included:

(1) the hydro regulations were run with reservoirs starting full in each of the 40 streamflow conditions as opposed to the 40 different reservoir refill conditions simulated in the initial study;

(2) the studies were run with the latest estimates of loads and resources submitted for the Pacific Northwest Coordination Agreement 1982-83 modified regulation, an area slightly different from the PNUCC West Group used in the initial study;

(3) the length of the critical period is now 20 months as opposed to the 42 month critical period used in the initial study;

(4) the amount of top quartile DSI load served from shifted Firm Energy Load Carrying Capability (FELCC) was reduced; and

(5) contracts for the purchase of 12 percent of Centralia and Weyerhaeuser/Longview Fibre are assumed to extend only through June 30, 1983, in contrast to the initial proposal in which BPA included the output from these plants as a resource over the 42 month critical period (this new methodology is consistent with the JCP recommendation that because these resources are not needed for the entire critical period they should be excluded from the analysis beyond the contract date).

Following completion of the hydro regulations, the Pacific Northwest Coordinated System Federal system analysis was prepared to determine Federal nonfirm energy availability. The analysis developed for the final proposal assumes displacement of Federal purchased power before any service to the top quartile load. This assumption was made solely for ratemaking purposes and should not be interpreted as meaning that a decision has been made on the displacement policy which is being determined through a rulemaking process presently underway.

For the period for which the load/resource studies were developed, BPA has approximately 650 average megawatts of excess firm resources. The JCP recommended a reduction in costs of acquisitions and conservation to reflect this surplus. The Administrator agreed that the level of planned resource acquisitions should be reduced to a more modest level than that assumed in the initial proposal. BPA developed a near-term resource policy that addresses acquisition of resources and conservation during a surplus period. The focus of the policy is on cost-effective resources that will minimize BPA cash flow requirements and adverse environmental impacts.

The Administrator decided that BPA should limit its resource acquisitions for FY 1983 to 12 percent of Centralia and Weyerhaeuser/Longview Fibre for three-quarters of a year; $5.2 million associated with the Idaho Falls project; and $14.6 million for various resource acquisitions that are expected to be made in accord with BPA's near-term resource policy.

The Administrator also decided that new conservation programs must be consistent with the near-term resource policy. The Administrator agreed with a recommendation from the JCP that BPA's projected conservation expenditures in FY 1982 and FY 1983 should be reduced for the final proposal from the level initially proposed. The Administrator also agreed with the JCP that funding be reduced for the Solar Heat Pump Water Heater Program and the Section 6(a) Acquisitions Program.

With respect to the shift of FELCC, the Administrator concluded that it would not be prudent to shift FELCC given the resource surplus BPA currently projects it will experience. However, he believes that a shift of FELCC can be used to reduce expensive resource purchases.

Repayment Study

BPA's statutory obligation is to set rates at a level sufficient to produce revenues that will recover the cost to BPA of producing, purchasing, and transmitting electric energy and repay BPA's investment in power facilities. In addition, BPA is required to pay the costs of its new responsibilities under the Regional Act. A Repayment Study is prepared to calculate the minimum level of revenue required to recover all costs over the repayment life of the facilities.

The Repayment Study prepared by BPA to test the adequacy of revenues from existing rates, assuming average water conditions, demonstrated that those revenues are insufficient to fully recover all costs as required. Since power and transmission rates were last adjusted in July 1981, significant increases have occurred in: (1) the cost of nuclear power plants from which BPA expects to acquire power generation capability; (2) costs to operate, maintain, and construct new Federal generation and transmission facilities; and (3) interest costs. A revenue increase also is needed to enable BPA to repay its deferred annual expense. BPA has made a commitment to fully repay its cumulative deferral over the 3 year period, FY 1983 through FY 1985.

Repayment and Revenue Requirement Issues

The Administrator adopted and incorporated into the final proposal many of the suggestions submitted in the JCP, as well as those made by other parties and participants. The Administrator concurred with suggestions from parties concerning the treatment of conservation program bonds and decided that in the final proposal conservation program bonds should be treated in the same manner as BPA treats construction bonds. The bonds are considered for repayment using the highest interest rate first criterion. The Administrator also determined that BPA should lower the projected inflation rates from the level used in the initial proposal to reflect current conditions. The Administrator agreed with comments from the parties concerning the inclusion of actual data from bond sales in determining the level of Washington Public Power Supply System (Supply System) costs for projects Nos. 1, 2, and 3. He decided that BPA should revise its determination of costs for Supply System projects 1, 2, and 3 to reflect February and May 1982 bond issues, a new schedule of bond issues for the remainder of the cost evaluation period, and the construction extension of project 1. The Administrator also concurred with the suggestion in the JCP that Trojan nuclear plant costs included in the initial Repayment Study were overstated. The costs are reduced in the final proposal.

The Administrator decided that the operations and maintenance cost data in the final proposal should be revised to reflect new budget estimates, a revised escalation factor, and more current historic information. He also decided that contributions to the Electric Power Research Institute (EPRI) should continue, but in light of current economic conditions the contributions should be held to the FY 1982 level.

In the final proposal, the Administrator decided to include an additional revenue requirement of $30 million for cash flow needs and to increase BPA's revenue requirements to cover the inclusion of a 5-year call provision for BPA's bonds. The JCP supported these revenue requirement increases.

It was recommended by the JCP that BPA use a linear programing approach to estimate its revenue requirement. The computer program that generates the Repayment Study was reviewed extensively by BPA and the parties and was found to be sound. The Administrator did not recommend changing the BPA model for a linear programing model because a thoroughly tested and documented linear program model does not exist for this purpose. However, BPA staff will continue to review and evaluate linear programing as an alternative approach for future use in modeling repayment requirements.

Time-Differentiated Long Run Incremental Cost Analysis

A Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis was prepared to determine the incremental costs BPA incurs on a seasonal, daily, and hourly basis to meet load growth requirements or costs that it avoids if customers do not demand additional increments. In the TDLRIC Analysis, expected additional demands on BPA's system and planned additions of generation and transmission facilities to meet these demands were analyzed. Rates based strictly on results of the TDLRIC Analysis would produce revenues in excess of BPA's revenue requirement. Therefore, the TDLRIC Analysis was used to develop illustrative TDLRIC rates, to provide the basis for the classification of certain generation costs between capacity and energy in the Cost of Service Analysis (COSA), and to identify the incremental cost of providing service at varying time periods in order to develop rates that are differentiated on a seasonal, daily, and hourly basis.

Time-Differentiated Long Run Incremental Cost Analysis Issues

The long run incremental cost (LRIC) of generation consists of both a capacity and energy component. The LRIC of capacity is based on costs of a generic

Cost of Service Analysis Issues

Functionalization

In functionalizing operations and maintenance costs, BPA functionalized those activities not clearly falling into the generation or metering and billing function to transmission. The Administrator recognizes that this aspect of the functionalization process can be made less subjective and more precise. However, BPA was not able to review alternative methodologies for this rate filing because time and staff resources were limited. However, alternative methods will be reviewed for potential inclusion in the next rate filing.

During the hearings it was suggested that BPA should not functionalize exchange resource costs to transmission. However, the Administrator determined that exchange transmission costs are legitimate costs of transmitting exchange power and must be functionalized to transmission so they can be allocated as transmission costs to customers deemed to be served by the exchange resources.

Classification

BPA apportions generation costs between capacity and energy according to the principle of cost causation. The costs are classified in relation to the causes underlying the construction and operation of the various plants. The Administrator believes this approach is more appropriate than other approaches because it best reflects the capacity and energy relationship developed during the planning of a hydro system, such as the Federal Columbia River Power System (FCRPS), and the differences between hydro and thermal resource operating characteristics.

BPA classified costs of those portions of hydro generating facilities installed solely for peaking to capacity. Costs of portions installed to provide energy and capacity were classified on the basis of the operating characteristics of the hydro system, resulting in one-half of the hydro system's critical water capability assigned to energy and one-half to capacity. Peaking capacity in excess of critical energy capability was classified to capacity.

BPA classified its thermal plants by using results of the TDLRIC Analysis to compare the cost of providing capacity and energy through construction of combustion turbines with the cost of providing capacity and energy through construction of a baseload thermal plant. Based on this analysis, BPA's thermal classification indicates that baseload thermal costs are primarily energy related. Based on an analysis presented by one of the parties, the overall TDLRIC classification percentages were applied to all thermal costs instead of the method used in the initial proposal which applied the TDLRIC fixed cost percentages to the fixed thermal costs.

BPA classified exchange resources on the basis of information supplied by exchanging utilities on how they classify their own resources. The Administrator believes that the utilities themselves rather than BPA are better able to develop classification percentages for their own resources.

Transmission costs were classified entirely to capacity. It was recommended that BPA classify a portion of its transmission costs to energy to reflect costs incurred to reduce line losses. The Administrator found this a valid suggestion. However, he decided that since a clear methodology for classifying transmission costs to energy has not been developed, BPA should continue to classify all transmission costs to capacity.

Seasonal Differentiation

BPA seasonally differentiated energy costs on the basis of energy produced from withdrawals of stored water in the reservoirs. Capacity costs were seasonally differentiated according to the probabilities of negative margin calculated in the TDLRIC Analysis. (The probabilities of negative margin measure the probability that capacity will be exceeded.) Transmission costs were not seasonally differentiated.

Allocation of Generation Capacity Costs

The rate directives section of the Regional Act defines three rate pools for which individual rates are to be developed. BPA initially proposed that capacity costs be allocated to the rate pools on the basis of energy received from the resource pools. In response to comment received, staff re-evaluated this approach and also evaluated five other possible methods for allocating resource pool capacity costs to the rate pools. Excess capacity exists on the system and BPA is currently unable to trace the origins of the capacity to each resource pool. It is reasonable to assume that excess capacity is supplied by each resource pool in proportion to its size. Therefore, each resource pool is "shrunk" by the percentage necessary to achieve load/resource balance. This balance is used to allocate the capacity to the rate pools. BPA's method of allocating generation capacity costs follows the priorities of the Regional Act, recognizes the differing capacity factors of the resource pools and load factors of the load pools, and assures that there are no unallocated capacity costs.

Allocation of Energy Conservation Costs

BPA initially proposed that costs associated with funding and operating its energy conservation programs be divided into two portions. One portion would be recovered through contractual provisions with utilities receiving conservation funds, whether or not they purchased power from BPA, and the second portion would be recovered through rates. The proposed contract charge feature of the initial proposal did not receive support from any of BPA's customers. For this reason, and because of the likely difficulty of incorporating a charge-back provision in the conservation contracts applicable to cost recovery in FY 1983, the Administrator decided the contract charge provision should be eliminated from this rate filing. The Administrator agreed with parties who suggested the most equitable method for allocating conservation costs is a cost-follows-benefits method. However, BPA staff indicated it was not possible to implement this method for this rate filing. Consequently, the Administrator decided to adopt the suggestion by one of the parties that a cost-follows-BPA-load method be used for this rate filing and that BPA continue to analyze alternative methods for use in future rate filings.

Other Allocation Issues

BPA functionalized and classified the costs associated with deferral of prior years' interest on the basis of the functionalization and classification of all other costs in the COSA. The Administrator decided that deferral costs should be allocated to all of BPA's customers on the basis of loads because the specific customers causing the deferral could not be identified accurately.

In the energy load/resource balance prepared to develop allocation factors, BPA increased the exchange load and resources by including exchange losses. The Administrator believes that because losses occur in the transmission lines of the exchanging utilities they must be accounted for to correctly determine the size of exchange loads and resources and correctly allocate costs. With respect to allocation of transmission costs, the Administrator determined that Federal transmission costs should be allocated to loads deemed to be served by Federal generating resources and exchange transmission costs allocated to loads deemed to be served by exchange generating resources.

Wholesale Power Rate Design Study

The Wholesale Power Rate Design Study represents the final step in the development of BPA's wholesale power rates. In this study, the allocated costs from the COSA are modified to account for the fact that revenues from certain rate classes will not necessarily equal allocated costs, to incorporate the rate design adjustments specified in the Regional Act, and to reflect results of the TDLRIC Analysis and BPA's rate design objectives.

Adjustments

Excess Revenues

During FY 1983, approximately $204.6 million in revenue from three sources is expected to be produced in excess of allocated costs. Excess revenues from the first source, the nonfirm energy (NF-2) rate, are credited to FBS, new resources, and transmission costs. Revenues from the generation portion of the standard NF-2 rate are split between FBS and new resources according to the total costs in each pool. Revenues from the generation portion of the spill rate were allocated to the FBS. This method was chosen because it tracks the rationale for and development of the NF-2 rate schedule. Excess revenues from the second source, revenue from sales to the DSI top quartile, are credited to FBS and new resources costs. Excess revenues from the third source, displaced new resources load served with Federal nonfirm energy are credited to FBS and transmission costs.

The FBS excess revenues continue to be classified between capacity and energy according to the reverse percentages developed in the TDLRIC Analysis. Allocation of most of the excess revenues to capacity bring the overall classification percentages closer to the TDLRIC percentages. This results in rates which send a more accurate price signal concerning the relative cost of capacity and energy.

Fixed Contracts

BPA provides service to certain customers under Canadian Treaty and Capacity/Energy Exchange contracts at contract rates that are not subject to change. The costs allocated to these services exceed the corresponding revenues. Therefore, BPA apportions these revenue deficiencies as adjusted for excess revenues from nonfirm energy sales, 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 Administrator decided the revenue deficiencies associated with these contracts should be allocated to the FBS resource pool because the benefits from the Canadian Treaty and Capacity/Energy Exchange are directly conferred on users of the FBS resources.

Value of Reserves

The value of reserves credit granted DSI's for the value of reserves provided by restriction rights in their contracts results in a revenue deficiency that must be classified and allocated to the rate classes. Although parties suggested various embedded methods for classifying the deficiency, the Administrator decided it was appropriate to classify it according to overall TDLRIC percentages. The costs of the credit were allocated to all firm customers, including DSI's, because Federal system reserves are provided to all firm loads, including three quartiles of DSI loads.

Low Density Discount

A low density discount (LDD) is included in the priority firm power (PF-2) rate. The revenue deficiency that results from granting the discount was first classified to capacity and energy according to the classification of all priority firm costs and then allocated to the priority firm customer class because this is the class that benefits from the LDD.

Hanna Adjustment

The establishment of a special rate for Hanna Nickel Smelting Company results in a revenue underrecovery that was allocated to all customers. The underrecovery was allocated to all customers because the special rate is justified based on regional and national benefits that result from the continued operation of Hanna.

Displacement

Assuming average water conditions in FY 1983, BPA would displace Weyerhaeuser/Longview Fibre and Centralia with nonfirm energy. Since displacement of these resources lowers the amount of nonfirm energy available for sale, the Administrator decided it was appropriate to assign the opportunity cost of those lost nonfirm sales to the users of those resources.

Equalization of Demand

Section 7(e) of the Regional Act allows BPA to equalize demand charges. The priority firm and annual and seasonal firm capacity rates were equalized. The capacity component of the industrial rate, new resources rate, and surplus firm power rate were set at the same level as the equalized priority firm and firm capacity rates by moving capacity dollars to the energy charge. Although some parties criticized the equalization process as defeating the purpose of the COSA, the Administrator decided that the equalization process facilitates administration of rates and insures that no customer has the incentive to purchase firm capacity under a capacity rate to avoid a higher capacity charge in a power rate.

Exchange Adjustment Clause

The exchange adjustment clause included in the initial proposal would have allowed BPA to collect any increases in exchange costs caused by an underestimation of the average cost of the exchange or the amount of exchange loads. Virtually all parties who commented on the adjustment clause opposed it. The Administrator agreed with a comment from the DSI's that accepting IOU forecasts of exchange costs uncritically may result in too high an estimate of exchange costs. For that reason he decided to adopt an exchange adjustment to deal with the problem. The Administrator is now proposing that the exchange adjustment be in the form of a rebate if the estimate of the average cost of the exchange for FY 1983 is less than forecasted. No surcharge will be assessed if the average cost of the exchange exceeds the forecast nor is there an adjustment for differences in the exchange load.

Wholesale Power Rate Schedules

The wholesale power rate proposal includes the following rate schedules: Priority Firm Power Rate Schedule, PF-2; Industrial Firm Power Rate Schedule, IP-2 (MP-2); Special Industrial Power Rate Schedule, SI-2; Firm Capacity Rate Schedule, CF-2; Emergency Capacity Rate Schedule, CE-2; Firm Energy Rate Schedule, FE-2; New Resources Firm Power Rate Schedule, NR-2; Surplus Firm Power Rate Schedule, SP-1; Surplus Firm Energy Rate Schedule, SE-1; Nonfirm Energy Rate Schedule, NF-2; Energy Broker Rate, EB-1; and Reserve Power Rate Schedule, RP-2. Of the 12 schedules, nine are successors of previous BPA wholesale power rates. The remaining three rate schedules, SP-1, SE-1, and EB-1, are new. The major issues associated with specific rate schedules are briefly discussed below.

Priority Firm Power Rate Schedule, PF-2

Public bodies, cooperatives, and Federal agencies, as well as investor-owned utilities participating in the residential exchange authorized by the Regional Act may purchase power for resale or direct consumption under the PF-2 rate schedule. It contains a demand charge that is diurnally and seasonally differentiated and an energy charge that is seasonally differentiated only.

The Administrator considered, but decided not to implement, a tiered rate structure for the PF-2 rate. The Administrator and many of the parties were concerned that tiered rates could adversely affect revenue stability, introduce inequities into the sale of priority firm power, increase BPA's administrative responsibilities, and potentially duplicate the function of BPA's billing credit program.

A low density discount was included in the PF-2 rate pursuant to Section 7(d)(1) of the Regional Act to alleviate adverse impacts of wholesale rate increases on retail rates of customers with low system densities. The discount is available to all PF-2 customers. In the initial proposal, circuit miles were used in the calculation of the physical system density ratio. The Administrator revised the calculation for the final proposal to reflect the suggestion from one of the parties that pole miles, not circuit miles, be used to measure physical system density. He believes that pole miles better describe the geographic distribution of a utility's consumers. The Administrator also decided that the discount for customers who serve areas both inside and outside the BPA region would be based only on that portion of their service areas that is in the BPA region.

When either a computed demand or contract demand customer takes power from BPA that is not contractually authorized, the Administrator may charge for the overrun or unauthorized increase. For the final proposal, BPA decided to base that charge on the incremental fuel costs of operating an oil-fired combustion turbine.

The Administrator concluded there was insufficient evidence on the record to support adoption of a separate charge in the PF-2 rate for transformation.

Industrial Firm Power Rate Schedule, IP-2 (MP-2)

The IP-2 (MP-2) rate schedule applies to sales of Federal power to BPA's DSI customers. The rate for IP-2 customers is the same as the rate for MP-2 customers except for the value of reserves credit. This credit is applied to the IP-2 rate in recognition of the value of reserves provided by BPA's rights to interrupt DSI load. This feature increases the reliability of service to other firm customers' loads when the Federal system is unable to meet its firm commitments as a result of insufficient generation or transmisssion capacity.

In the initial proposal, the IP-2(MP-2) rate schedule included a minimum bill to insure that BPA would collect at least a portion of the revenues forecasted to be received from the DSI's. The DSI's as well as some other customer groups criticized the minimum bill. Alternatives to the minimum bill were considered during the hearings and they too were opposed by the DSI's. Based on the record, the Administrator decided not to incorporate a minimum bill or many of the alternatives suggested. He adopted the DSI's suggestion that a lower, more realistic forecast of the DSI load be used. By forecasting 50 percent service to the top quartile instead of basing the forecast on availability, the risk of underrecovery by top quartile restrictions is balanced by the possibility of overrecovery if service is greater than forecasted.

BPA does not plan resources to serve the top quartile on a firm basis, so no costs other than transmission are allocated to the top quartile in the COSA. The top quartile is served with a combination of provisional drafts (shifted FELCC, advance energy, and flexibility) and nonfirm energy when available. BPA used an opportunity cost concept to assign costs to the DSI top quartile. That part of the top quartile served with shifted non-surplus FELCC was priced at the generation portion of the NF-2 standard rate, while the energy used to make up the remaining portion of the top quartile was valued at the generation portion of the average nonfirm energy rate for each month.

The DSI contract requires that BPA use surplus FELCC, to the extent it is available, to serve the top quartile. A DSI can indicate it wants to be served by surplus FELCC during specified periods of the year and then will be billed for its total load at the surplus FELCC rate during those periods, regardless of whether or not the top quartile is curtailed. The rate for customers receiving top quartile service with surplus FELCC was designed by removing the costs assigned to the top quartile and dividing by the lower three quartiles billing determinants.

BPA developed a value of reserves analysis to measure the benefit resulting from the ability to restrict the DSI load. In the study, the Federal system reserves were segmented into forced outage reserves, stability reserves, and plant delay reserves. Reserves were valued by determining expected use in conjunction with power sales contract provisions.

BPA based its determination of the value of forced outage reserves provided by DSI's on the costs of a combined cycle combustion turbine. Parties suggested that BPA use other alternative resources, including purchase power, surplus capacity and a single-cycle combustion turbine to value the forced outage reserve. The Administrator concluded that purchased power and surplus capacity lacked reliability and that the single-cycle combustion turbine would not be the least cost resource for providing capacity and energy over the long term. In both the initial and final proposals, the value of stability reserves was determined as the annual cost of an alternative load tripping scheme. BPA assigned no value to plant delay energy reserves because no new plants are scheduled to come on-line in the test year. BPA used a share the savings methodology to calculate the size of the credit given to the DSI's.

Special Industrial Power Rate Schedule, SI-2

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. The granting of a special rate was opposed by many parties because Hanna is not operating now and might not resume operation in FY 1983. However, the Administrator concluded that a special rate is appropriate for Hanna because Hanna submitted testimony indicating that without a special rate it would be more difficult to reopen. Furthermore, the Administrator concluded it would be expensive and untimely for BPA and Hanna to begin negotiating a special rate after Hanna decided to resume operations. The Administrator agreed with many of the criticisms of the methodology used in the initial proposal to design the SI-2 rate. Therefore, the SI-2 rate has been set equal to the PF-2 rate in order to approximate the rate Hanna would have paid absent the Regional Act.

Wholesale Firm Capacity Rate Schedule, CF-2

The CF-2 rate schedule applies to capacity sales for utilities purchasing firm capacity either on a yearly or seasonal basis. Energy associated with delivery of capacity is returned to BPA. To encourage capacity purchasers to limit their use of Federal generating facilities and maximize use of their own facilities, the CF-2 rate includes an additional monthly charge for capacity taken in excess of 9 consecutive hours per day. 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.

New Resources Firm Power Rate Schedule, NR-2

The new resources rate, NR-2, applies to purchases of firm power for resale or direct consumption by regional IOU's under net requirement contracts and to purchases by public body, cooperative, or Federal agency customers to serve new large single loads. In the initial proposal, the NR-2 rate consisted of a base rate, based on the lowest cost resources assigned to the new resources load. As purchases exceeded the annual average output of the lowest cost resources and BPA purchased additional resources to serve the load, the rate increased. In response to comments from parties advocating that the rate be fixed, the Administrator decided to establish a fixed rate based on costs of exchange resources most likely to be associated with an NR-2 load. The need for a flexible rate based on a meld of exchange and new resources is obviated by the closeness in unit costs between exchange resources and non-discretionary new resources.

Nonfirm Energy Rate Schedule, NF-2

The NF-2 rate applies to purchases of nonfirm energy both inside and outside the Pacific Northwest. The NF-2 rate is intended to promote greater customer acceptability than the current nonfirm energy rate, while allowing benefits from the availability of nonfirm energy to be equitably shared. The NF-2 rate schedule has three components: (1) a standard rate in effect at all times except when a spill or imminent spill condition exists, (2) a spill rate, and (3) an incremental rate applied to sales of energy with an incremental cost greater than the standard rate.

Under the standard rate, 50 percent of each maximum hourly amount will be offered with a one day guaranteed delivery provision. The rate was determined by dividing BPA's total costs, excluding residential exchange program costs, by total firm and nonfirm energy sales, excluding exchange energy. The California utilities disagreed with the way the standard rate was calculated, arguing that it should not reflect costs that do not contribute to the availability of nonfirm energy. The Administrator does not agree that only the costs of resources contributing directly to nonfirm energy should be included in the standard rate. The Administrator believes other costs are incurred as support services for power generation. In addition, because the majority of nonfirm energy is made available from FBS resources, all FBS costs should be included in the NF-2 standard rate.

Despite numerous comments, especially from California parties, that the standard rate should include a greater or longer guarantee, the Administrator decided the 50 percent one day guarantee provision was appropriate. The Administrator believes that increasing the percent offered on a guaranteed basis above 50 percent or extending the guarantee for 3 days, as was suggested, would reduce the amount of NF-2 energy BPA would be willing to sell. The Administrator evaluated an alternative NF-2 standard rate suggested by the California parties under which guaranteed energy would be delivered, but subject to return under certain circumstances, and found it unworkable. The Administrator has stated BPA will strive to make its best estimate of available nonfirm energy for the second and third days available to potential purchasers, although the nonfirm energy cannot be offered on a guaranteed delivery basis. Although both Northwest public agencies and investor-owned utilities testified that they would prefer to have none of the NF-2 standard rate energy offered on a guaranteed basis, the Administrator believes the proposed guarantee represents a workable compromise and will not significantly reduce the amount of available nonfirm energy.

BPA based the spill rate on the value of spill energy to Northwest thermal operators. The spill rate was diurnally differentiated in the initial proposal, but not in the final proposal.

The Administrator has decided that the incremental rate should be equal to the incremental cost of producing or purchasing the energy plus 2 mills per kilowatthour. The incremental rate included in BPA's initial proposal contained a 15 percent adder. The California utilities criticized the adder for not being cost-based and suggested a 1 mill adder be used. The Administrator decided that a 2 mill adder would be appropriate and would represent a reasonable compromise between the initial proposal, which would result in a 4.5 mill adder for a 30 mill resource, and the 1 mill proposal by the California utilities.

Surplus Firm Power Rate Schedule, SP-1

BPA also offers a surplus firm power rate. Many parties criticized the initial schedule for its lack of specificity and clarity and suggested that the resources being sold and their costs should be more clearly identified. In the final proposal, the size of the surplus has been identified and costs allocated to it in the COSA. The rate now consists of a fixed rate based on the costs of the resource and a formula rate application if the surplus is from discretionary resources that had not been allocated to the rate.

Surplus Firm Energy Rate Schedule, SE-1

Because it is possible to have surplus firm energy without surplus capacity in the FCRPS, and possible to market surplus firm energy to capacity customers, the Administrator is offering a surplus firm energy rate, SE-1, in the final proposal. The SE-1 rate is set at the same level as the SP-1 energy charge. It is expected that most surplus firm energy purchases will be made at this rate, but as with the SP-1 rate, other specific conditions of sale under will be determined in individual contracts transacted with eligible customers.

Energy Broker Rate, EB-1

The Energy Broker rate schedule applies to energy sold through the Western Systems Coordinating Council's energy broker program. BPA will use the broker for energy sales only after all available markets have been served under the nonfirm rate schedule.

National Environmental Policy Act

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 examined revenue level and rate design alternatives including those that represent the upper and lower limits of potential environmental impact.

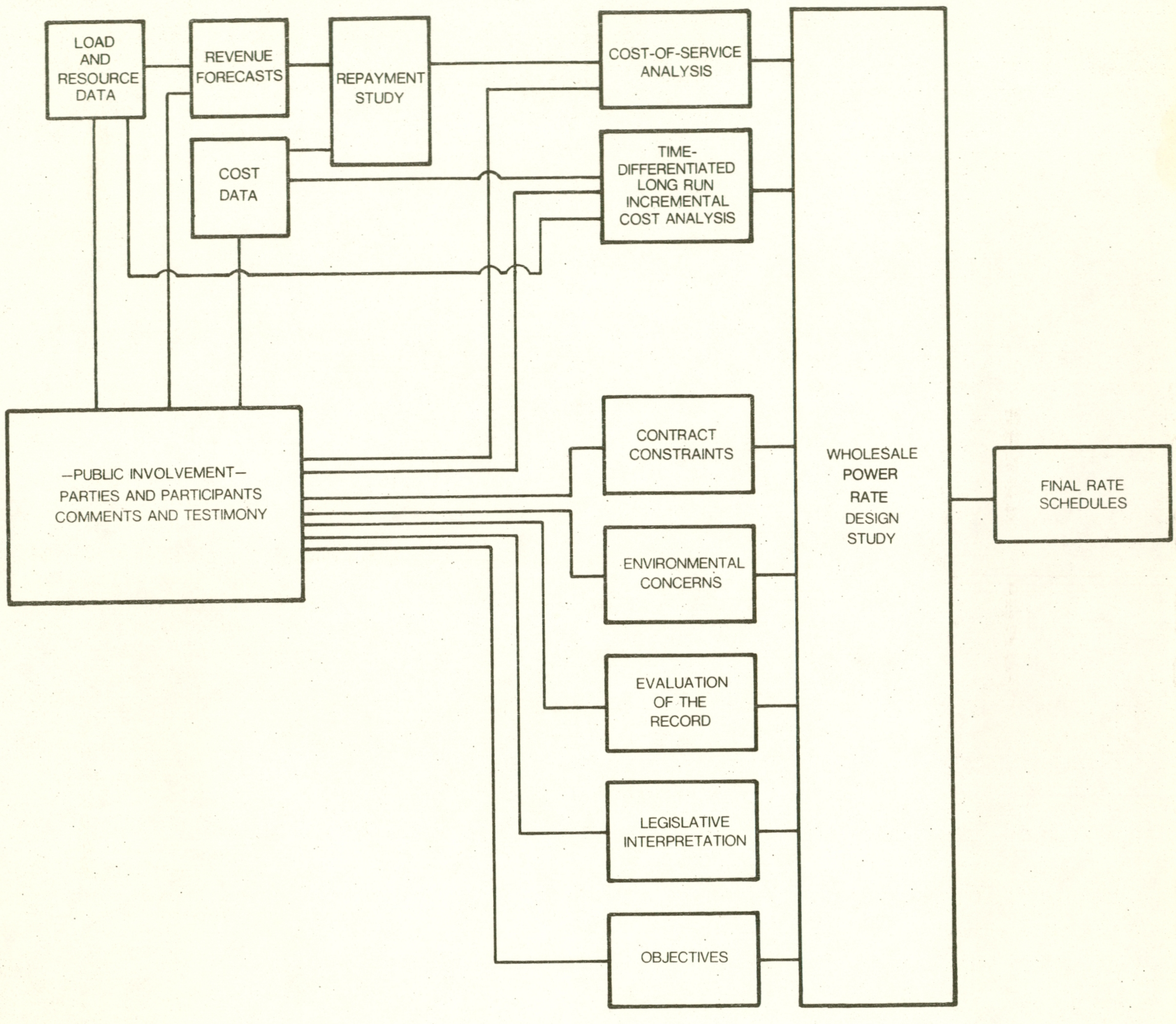
The revenue level alternatives BPA considered included: (1) a no action alternative under which BPA would maintain its existing rate structure; (2) an alternative under which certain assumptions in BPA's Repayment Study would be modified to reduce BPA's revenue requirements; (3) a long run incremental cost (LRIC) alternative that would base rates on the projected long run incremental cost of acquiring new power resources in the Pacific Northwest; (4) an alternative that would phase in LRIC rates over a 5-year period; and (5) the proposed alternative. The Administrator concluded that the proposed revenue level alternative represents a reasonable balance between impacts to the physical environment and impacts to the socioeconomic environment and therefore is the preferred alternative. It recognizes both the need to minimize potential adverse impacts to the physical environment associated with increases in the use of electricty, as well as the need to take account of the socioeconomic consequences of increases in electricity rates.

The EIS evaluated alternatives to BPA's proposed schedules for the sale of priority firm power, industrial and modified firm power, new resources firm power, nonfirm energy, and firm capacity. Alternatives to the other rate schedules were not considered because it is not anticipated that revenues from sales under these rates or associated environmental effects will be significant.

The alternatives considered to the proposed structure of the priority firm rate included tiered rates and rates based on the inverse elasticity principle. Alternatives to the industrial firm power rate schedule that were examined include eliminating a value of reserves credit, providing a different amount of credit, applying the credit in a different manner, or tiering the rates. As alternatives to the proposed new resources rate, the EIS examined a rate schedule similar to the existing rate and a rate schedule containing two levelized rates. Alternative nonfirm rate schedules considered included a schedule similar to the existing schedule, a share-the-savings rate similar to BPA's 1979 nonfirm energy rate, and a flat rate. Also examined were alternatives to the firm capacity rate. These included a firm capacity rate with no additional monthly charge for capacity in excess of 9 hours per day and a time-differentiated rate. The Administrator concluded that the rate design alternatives adopted in BPA's proposal best meet BPA's rate design objectives. The proposed rate design alternatives would not cause environmental impacts significantly different from those experienced under BPA's current rate design.

(WP-PLA-0811m)

RATE DEVELOPMENT PROCESS



DATE DUE
