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**Bonneville Power Administration
1983 Wholesale Power Rate
Final Environmental Impact Statement**

U.S. Department of Energy



September 1983



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COVER SHEET

U.S. DEPARTMENT OF ENERGY
(DOE/EIS - 0102-F)

1983 WHOLESALE POWER RATE
FINAL ENVIRONMENTAL IMPACT STATEMENT

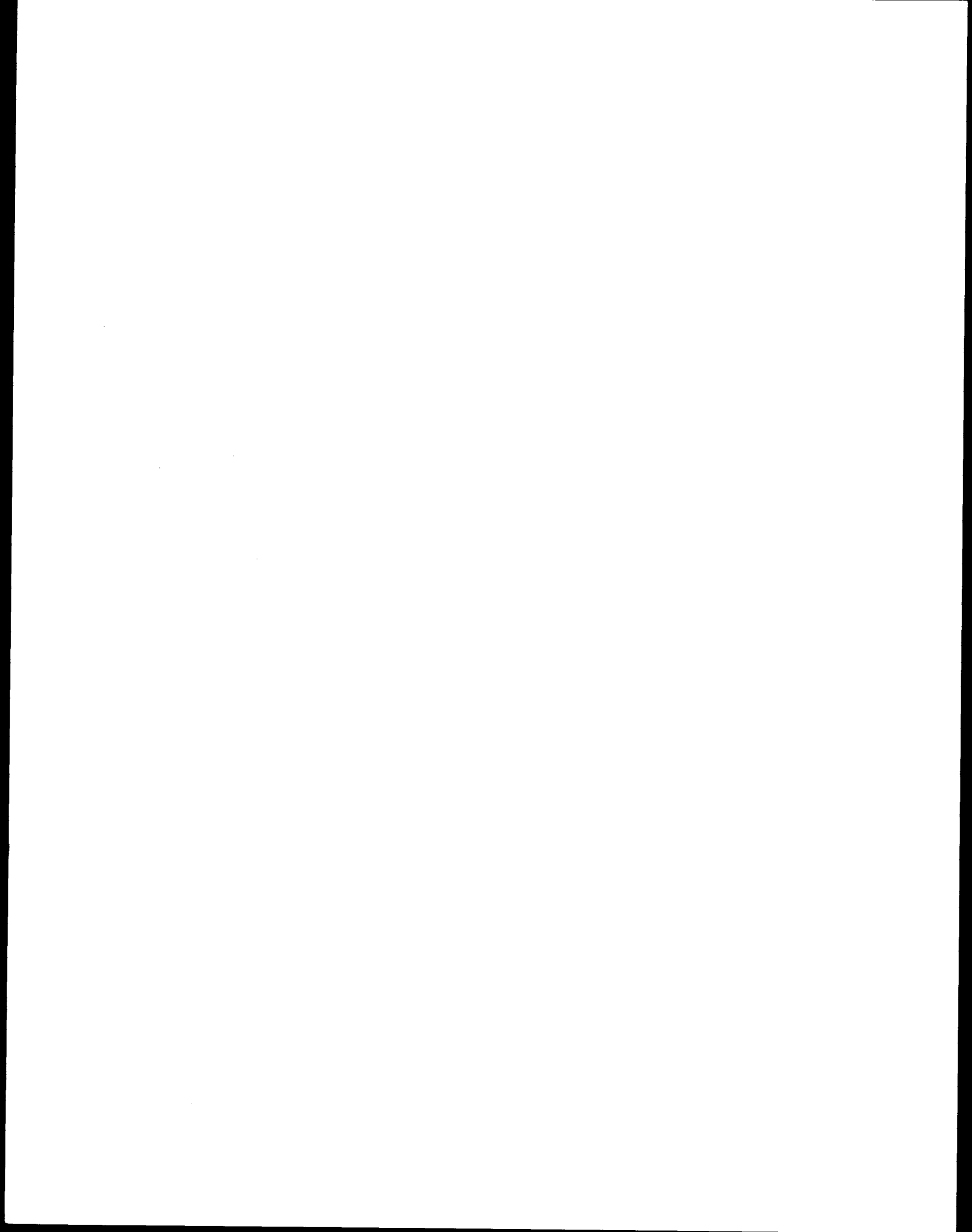
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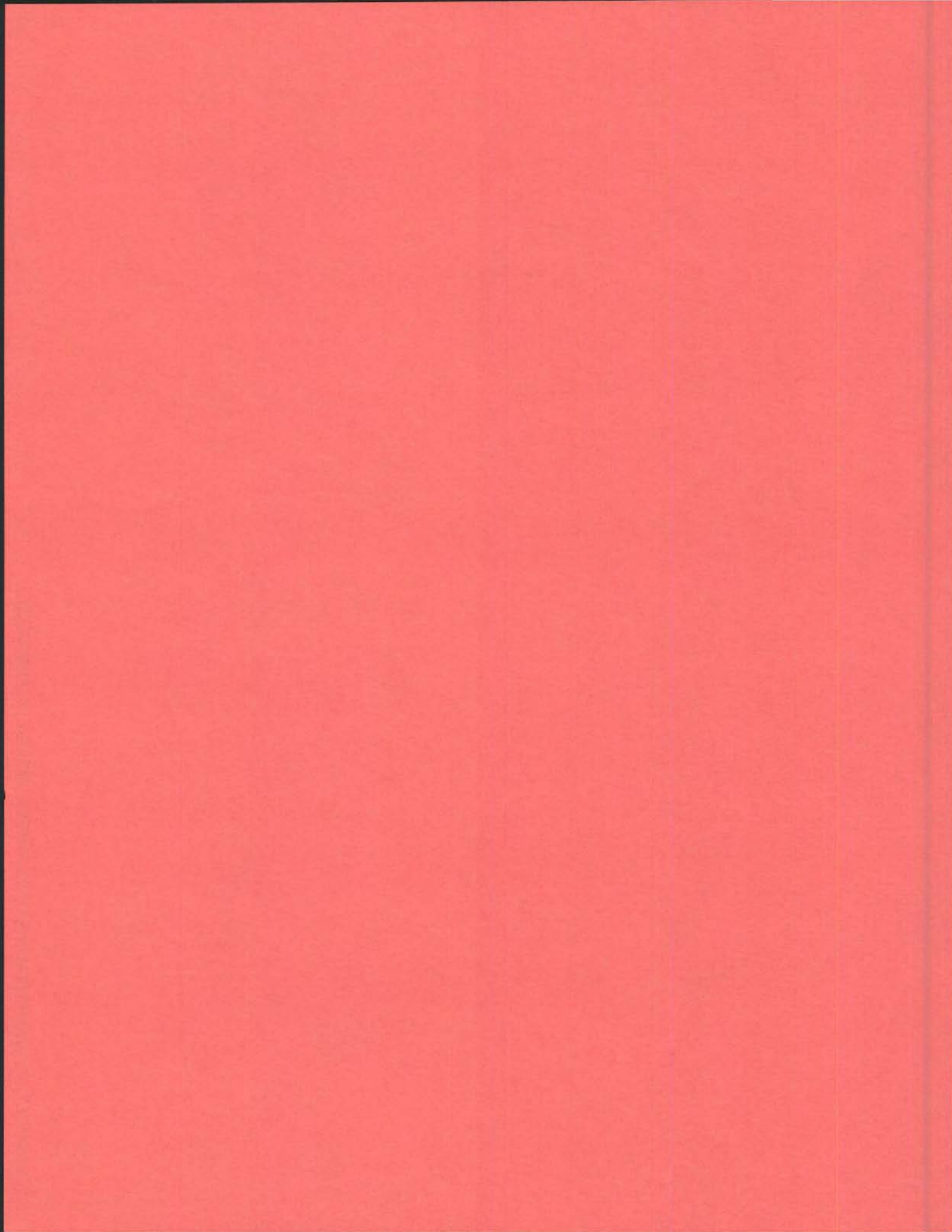
Abstract

This statement addresses the potential environmental effects of a wholesale power rate increase by Bonneville Power Administration (BPA). This action applies to the Pacific Northwest region and other areas, particularly California, which purchase power from BPA. Five different rate levels are analyzed. These range from a base rate alternative, the lowest level of rates, to a long run incremental cost (LRIC) alternative, the highest level. The no action alternative, the direct financing alternative, and the proposed alternative fall between these extremes. The proposed alternative reflects BPA's initial rate proposal, which increases the Priority Firm and Industrial Firm Power rates by 27 percent and 5 percent respectively, for the rate period November 1, 1983, through June 30, 1985. By the year 2000, power consumption under the direct financing, proposed, no action and base rate alternatives is forecast to be 17, 20, 22, and 32 percent greater, respectively, than under the LRIC alternative. The LRIC alternative may force closure of most plants operated by BPA's direct service industrial customers. Sprinkler irrigation development over the next two decades may be slowed by 50 percent of the growth rate forecast compared with the four alternatives. In the long run the LRIC alternative would reduce the construction and operation of major new generation resources and encourage the highest level of conservation.

Analyses have also been conducted concerning the effects of alternative rate structures. The existing and proposed rates are time differentiated and contain a variety of features to increase the efficiency of use of BPA's resources, and to minimize the need to construct or operate additional resources. This minimizes the environmental effects from resource construction and operation. Measures which mitigate the impact of wholesale power rate increases include BPA's conservation programs, rate design features which maximize efficiency, and others which reduce the level of rates for particular customer groups. The supporting documentation for the draft statement has been published as a separate appendix and is available upon request. For a detailed description of the DOE internal review process, see Chapter I.H. Comments on this final EIS must be made to FERC and received by the time FERC makes final approval.



Summary



1983 BPA WHOLESALE POWER RATE INCREASE
ENVIRONMENTAL IMPACT STATEMENT EXECUTIVE SUMMARY

A. Introduction

This environmental impact statement (EIS) has been prepared in an effort to address the potential environmental effects of a wholesale power rate increase proposed by Bonneville Power Administration (BPA) for implementation on November 1, 1983. The analyses described herein pertain to the potential effects of the 1983 initial wholesale rate proposal both in isolation from and in combination with recent rate increases as well as comparative analyses of the effects of reasonable alternatives to the proposed rates.

B. Purpose and Need

The purpose of BPA's proposed November 1, 1983, rate increase is to enable the agency to comply with the legislative requirement that it recover through revenue from power sales all costs required to operate and maintain the Federal Columbia River Power and Transmission Systems, to acquire purchase power, to repay with interest Federal investment in power generation and transmission facilities and to fund various fish and wildlife and conservation programs as specified in the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). The proposed rate increase would raise additional revenue during the period from November 1, 1983, through June 30, 1985, of approximately \$700 million. The Priority Firm rate would increase 27 percent, while the Industrial Firm Power rate and the New Resource rate would increase slightly. Without the proposed increase, it is forecast that revenue over this period would be about \$3.9 billion.

Several factors have contributed to the need for a rate increase. First, sales under current rates have been lower than anticipated and are expected to result in a revenue deficiency for fiscal year (FY) 1983. BPA will also be recovering, for the first time, operational costs for Washington Public Power Supply System (Supply System) Nuclear Project No. 2 (WNP-2) which is scheduled to begin operation in February 1984. Finally, the cost and amount of residential exchange power which BPA is required to purchase will be increasing throughout the rate period. The amount of BPA's proposed increase is designed to respond to these circumstances.

C. Alternatives and Their Impacts

The alternative actions, including the proposed action, and their potential environmental effects are analyzed from two perspectives. First, the effects of four potential revenue levels are considered. These include (1) a base rate alternative; (2) a no action alternative; (3) the proposed revenue level; (4) a direct financing alternative; and (5) a long run incremental cost (LRIC) revenue level. The base rate analysis is designed to indicate what could have been expected had BPA's rates remained at the levels established in 1974. This alternative thereby establishes a base against which the cumulative effects of all subsequent rate increases (i.e., BPA's

1979, 1981, 1982, and proposed 1983) can be evaluated. The no action alternative assumes a revenue level equal to that which would be achieved during the rate period under existing rates. BPA's initial rate proposal forms the basis for the proposed revenue level alternative. The initial proposal would increase the Priority Firm, Industrial Firm, and New Resources Firm rates by 27 percent, 5 percent, and 1.4 percent, respectively. The Surplus Firm rate would decrease by 6 percent, while the Nonfirm Standard rate and the Nonfirm Spill rate would increase by 14 percent, respectively. The direct financing alternative assumes a revenue level which is needed to complete WNP-2 and to keep WNP-3 on its construction schedule. The revenue level assumed under the LRIC alternative is based on the amount of revenue which BPA would recover during the rate period if rates were set at BPA's long run incremental cost of providing service.

Following the analysis of the varying effects of alternative revenue levels is a discussion of the effects of rate structure. Each of BPA's existing and proposed rate schedules and their impacts are discussed. Additional alternatives, including tiered rates, differences in cost classification strategies, changes in rate design adjustments, expanded use of time differentiation, and variations in cost allocation methods are considered.

The general conclusions of the revenue level analyses are that the base rate alternative would have the most beneficial short range socioeconomic benefits. This alternative would, however, result in the highest level of electricity consumption and associated impacts stemming from the construction and operation of power generation facilities. It would also produce the lowest level of environmental impact associated with the direct use of alternative use of fuels such as wood, oil, and natural gas. Conservation actions would be minimal under the base rate alternative.

For each category of impact, the strength of effect varies along a continuum with the extremes being defined by the base rate and LRIC alternatives. The effects of the no action and proposed and direct financing alternatives fall between these extremes with the effects of the proposal being somewhat closer to those of the LRIC alternative than is the case for the no action alternative. As a practical matter, there is little difference between the effects of the no action and proposed alternatives.

From a cost recovery standpoint, only the proposed action would allow BPA to recover its revenue requirement without generating substantial excess revenue (as would be the case under LRIC pricing). The base rate would not produce revenue sufficient to allow BPA to continue operation and the no action alternative would produce a substantial revenue shortfall (equal to approximately 15.4 percent of the forecast revenue requirement) which would ultimately need to be recovered from future ratepayers.

By the year 2000, power consumption under the direct financing, proposed, no action, and base rate revenue levels is forecast to be 17, 20, 22, and 32 percent greater, respectively, than under the LRIC alternative. In terms of electric generating plant capability and conservation, this means the direct financing, proposed, no action and base rate alternatives would require, respectively, 2,467, 3,522, 5,129, and 7,520 installed (nameplate) megawatts of resource capacity over that required under the LRIC alternative.

LRIC pricing would probably force closure of the plants of most of BPA's direct service industrial customers. The operations of these plants have been significantly curtailed even under current rates, although they are forecast to increase considerably under either the proposed or no action alternatives as the national economy improves. The base rate would be expected to strongly encourage return to full operational levels as well as substantial investment in future plant expansions, leading to future increases in electrical demand.

Irrigated agriculture would be expected to grow somewhat under all revenue level alternatives, although the least amount of growth would occur under the LRIC alternative. A large percentage of net irrigation development would be expected to use gravity methods. This would result in reduced on-farm electricity loads and increased water use. This would have adverse water quality effects and reduce the amount of water available for power production. Approximately 4 million acres of cropland are currently sprinkler irrigated in the region. This total would be expected to increase by about one-half a million acres by the year 2000 under the base rate, no action and proposed alternatives. This rate of growth would be cut approximately in half under the LRIC alternative.

Turning from the effects of revenue level to rate structure, the analysis of the effects of rate structure or rate design focuses individually on each of BPA's existing and proposed rate schedules. No further alternatives beyond the existing and proposed alternatives were considered for rate schedules pertaining to the sale of emergency capacity, surplus firm energy, reserve power, special industrial firm power, or power sold through the energy broker system since none of these service categories is expected to account for substantial amounts of revenue and none appear to have a potential for environmental impact. Additional alternatives were considered for the rate schedules pertaining to sale of priority firm, industrial firm, new resources firm and surplus firm power as well as nonfirm energy and firm capacity.

The demand and energy charges of most existing and proposed firm power rate schedules are time differentiated. Time differentiation of rates enhances the efficiency of use of BPA's resources, thereby minimizing the need to add new facilities with their attendant construction and operational effects. Thus, the time differentiation of these rate schedules is expected to be environmentally preferable to the use of alternative non-time-differentiated rate designs.

The seasonal periods for the demand charges for the seasonally differentiated rates have been changed slightly under the current proposal. The month of May has been shifted from the winter to the lower cost summer period to reflect the decreased probability of a load loss during May due to fish enhancement activities. This shift should benefit irrigators since May is a part of the irrigation season.

The existing and proposed firm capacity rate schedules contain an additional charge which is applied to sustained peaking capacity taken in excess of 9 hours. Again, this feature is believed to enhance the efficiency of operation of BPA's resources and thereby offers an environmental benefit.

The existing and proposed industrial firm power rates contain a value of reserves credit. The credit is intended to partially compensate BPA's direct service industrial customers for certain rights BPA has to restrict service to the industries. These restriction rights permit BPA to avoid the expense and the adverse construction and operational environmental effects which would result from replacing the restriction rights with physical facilities to provide reserves.

BPA offers a low density discount in its existing and proposed priority firm power rates. The discount is intended to mitigate the adverse impacts associated with low system densities which would otherwise be reflected in the retail rates of many rural utilities. The discount is provided for in the Regional Act.

The special industrial rate which BPA offers to Hanna Nickel is intended to avoid the adverse impacts due to increased rates. The special rate to Hanna is provided for in the Regional Act.

Finally, both the existing and proposed priority firm rates include rate design adjustments which reflect the results of BPA's Time Differentiated Long Run Incremental Cost Analysis. These include the allocation of fixed contract deficiencies, and the crediting of excess revenue from nonfirm sales. The method of these adjustments is intended to encourage more efficient use of BPA's resources, thereby minimizing the need for additional facilities with their attendant physical and economic consequences.

D. Mitigating Measures

Mitigating measures could be applied by various entities to reduce the effects of increasing wholesale rates. Existing and proposed conservation programs offer some assistance. Since 1981, BPA has been offering energy conservation programs targeted at primary customer groups, state and local governments, and nonprofit consumers in the Pacific Northwest. Most of the conservation programs are directed at reducing energy used in space and water heating, lighting, and industrial processes.

One potential mitigating measure is BPA's billing credit program, designed to reduce BPA loads, and consequently the revenues and level of rate increases needed by BPA in the future. Mandated by the Regional Act, billing credits are payments from BPA to eligible customers for actions that reduce their power needs and BPA's obligation to acquire additional generation resources.

Other mitigating measures include Government income support programs, such as the Federal Low-Income Energy Assistance Program, which help eligible low income consumers to cope with increased electricity rates. As previously discussed, BPA's low density discount and the restructuring of seasonal capacity periods also mitigate the impact of the proposed rates on certain customer groups.

E. Areas of Controversy

Certain issues addressed in the EIS pertaining to rate design have generated significant controversy.

Concern has been raised over the magnitude of BPA's recent rate increases. Customer groups, as well as end use consumers, have opposed the size of the increases and offered suggestions for reducing costs and lowering the amount of revenue needed by BPA. Some participants in the rate cases have suggested that the revenue level should encourage efficient use of resources, rather than to simply meet financial obligations (i.e., be as low as possible). In particular, the issue of LRIC pricing has received considerable attention.

Although a revenue level increase impacts all customer groups, particular concern has arisen about the impacts on low-income consumers, irrigated agriculture, and direct-service industrial customers, and industrial customers of retail utilities. The impact of rate increases implemented or anticipated to be implemented during the 1979-1983 period has been the subject of considerable controversy.

Attention also has been drawn to certain rate design issues, including design of the nonfirm and the industrial firm power rates. Some concern has been expressed about the marketability of some types of BPA power and the need for the design of rates which enhance marketability.

F. Issues to be Resolved and Choices Among Alternatives

To develop proposed rates, BPA examined and resolved a number of issues concerning revenue level, rate design, and impacts. BPA identified a number of objectives, including among others, statutory requirements, environmental impacts, equity, and efficient use of resources. Among these objectives, adherence to statutory requirements was assigned first priority.

Of the five revenue level alternatives considered in the EIS (i.e., base case, no action, direct financing, proposed, and LRIC), BPA believes that the revenue level proposed for the rate period represents the most reasonable choice. The proposed revenue level meets BPA's statutory requirements and financial obligations while achieving rate equity. It is difficult to select the revenue level alternative that would be most desirable from an environmental standpoint. In the short run, with the possible exception of irrigated agriculture, the alternatives that have the most positive effect on the physical environment generally have the most negative effect on the socioeconomic environment and vice versa. However, in the long run, an alternative which would have a positive effect on the physical environment also could have a positive effect on the socioeconomic environment. Impacts of the proposed alternative fall between the extremes established by the base case and LRIC alternatives.

The EIS identified the potential for significant effects of the proposed revenue level on low-income consumers, irrigated agriculture, and BPA's direct service industrial customers. Certain aspects of the proposed rate designs will partially mitigate these impacts. Various conservation programs offered by BPA may help further alleviate the adverse impacts of increased rates.

Given its rate design objectives, BPA believes that its proposed rate alternatives represent the most reasonable alternatives.

H. Appeal Process From Administrator's Record of Decision

BPA will make and record a decision on its 1983 wholesale power rates at the same time it publishes this Final Environmental Impact Statement. The Regional Act established a formal internal appeals process within the Department of Energy that allows other agencies and the public to appeal the Administrator's Record of Decision on BPA's 1983 Wholesale Power Rates. The Regional Act provides that BPA rates are effective only upon a finding by the Federal Energy Regulatory Commission (FERC) that the rates: (1) are sufficient to assure repayment within a reasonable number of years of the Federal investment in the Federal Columbia River Power System, after first meeting the Administrator's other costs; (2) are based on BPA's total system costs; and (3) reflect an equitable allocation of Federal Transmission System costs.

Pending final approval, FERC may also approve the final rates submitted by the Administrator on an interim basis. Revenue from rates approved on an interim basis is subject to refund with interest.

FERC intervention regulations grant to members of the public broad rights to intervene and make their views known concerning confirmation and approval of BPA's rates. Members of the public may establish their right to intervene before FERC by asserting: (1) a statutory right to intervene; (2) an affected interest which is not adequately represented by existing parties; or (3) petitioners' participation to be in the public interest. Any member of the public who desires to intervene before FERC in the final confirmation and approval process, or any interim approval proceeding, must file a timely petition to intervene with FERC. Time deadlines and required contents of petitions are set forth in FERC's general regulations.

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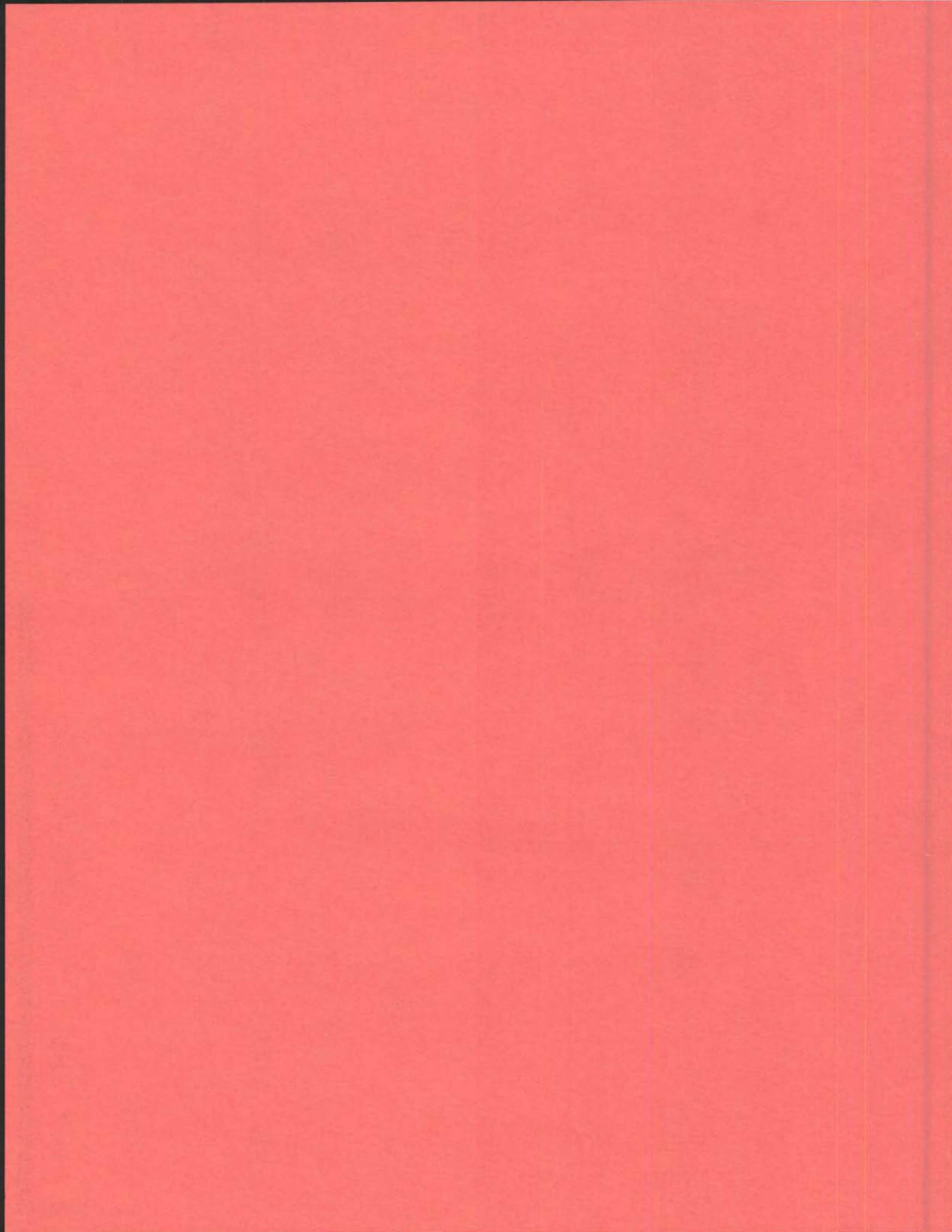


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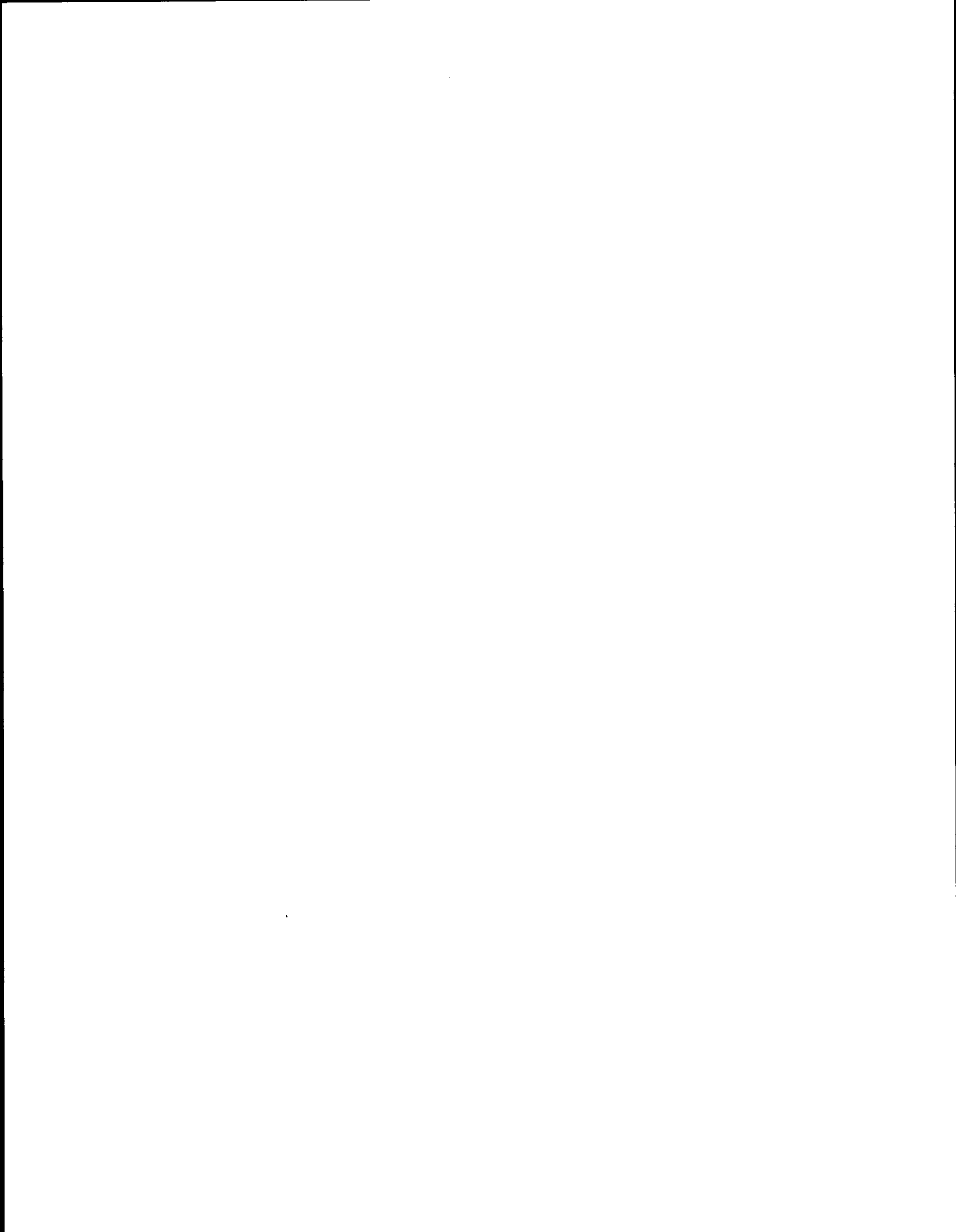
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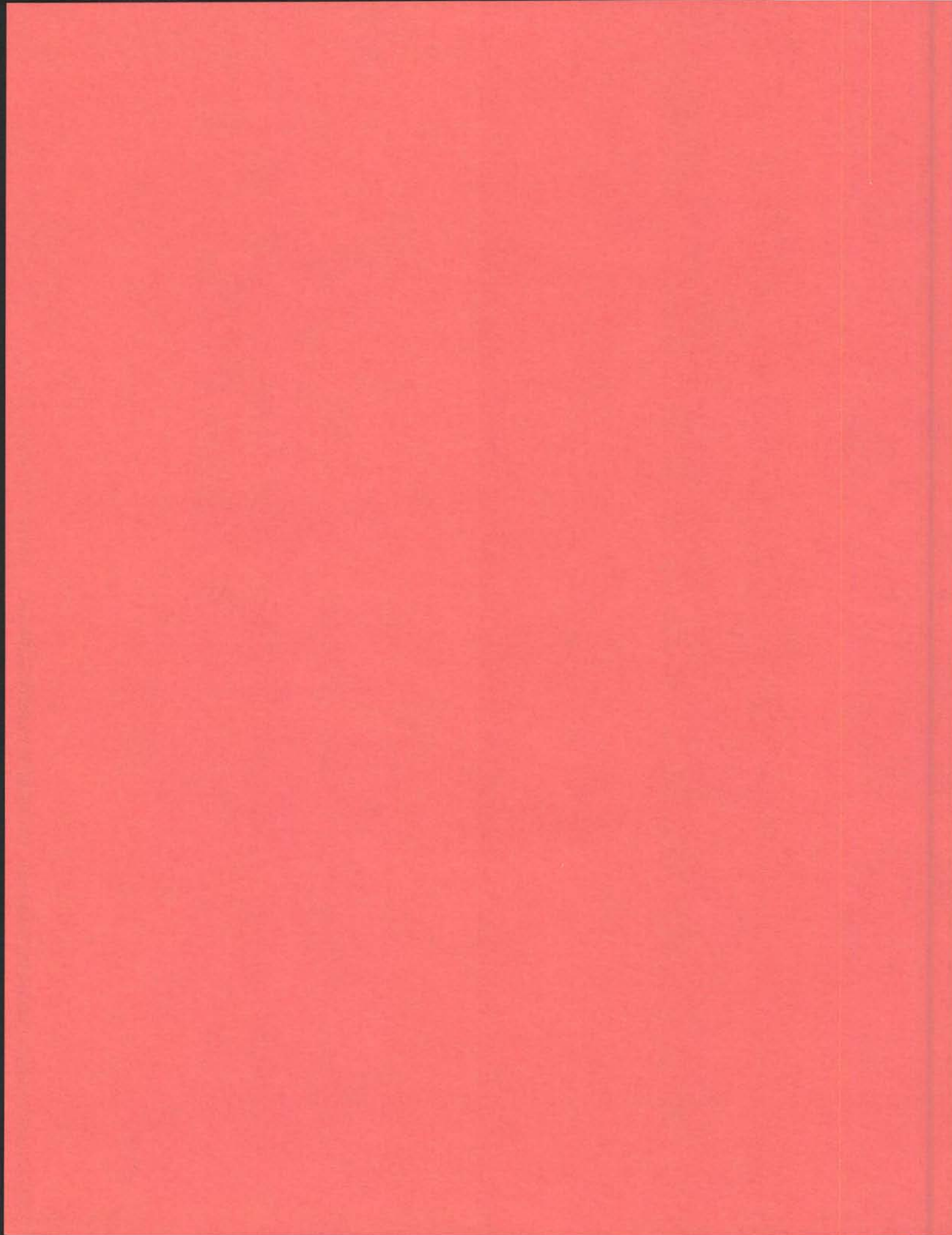
LIST OF ABBREVIATIONS

BLS	Bureau of Labor Statistics
BPA	Bonneville Power Administration
BTU	British Thermal Unit
CEQ	Council on Environmental Quality
CF	Wholesale Firm Capacity Rate
COSA	Cost of Service Analysis
CSPE	Canadian Storage Power Exchange
Council	Northwest Power Planning Council
DEQ	Department of Environmental Quality
DOE	Department of Energy
DSI	Direct Service Industrial Customer
EB	Energy Broker Rate
EIS	Environmental Impact Statement
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
FY	Fiscal Year
GWh	gigawatthour (equals 10^6 kWh)
IOU	Investor Owned Utility
IP (MP)	Industrial Firm Power Rate
LRIC	Long Run Incremental Cost
MW	Megawatt
MWh	megawatthour (equals 10^3 kWh)
NEPA	National Environmental Policy Act of 1969
NEPP	Northwest Energy Policy Project
NF	Nonfirm Energy Rate
NR	New Resources Firm Power Rate
ORNL	Oak Ridge National Laboratories
OY	Operating Year
PF	Priority Firm Power Rate
PNW	Pacific Northwest
PUD	Public Utility District
PURPA	Public Utilities Regulatory Policies Act of 1978
REA	Rural Electrification Administration
RP	Reserve Power Rate
Regional Act	Pacific Northwest Electric Power Planning and Conservation Act of 1980
SE	Surplus Firm Energy Rate
SI	Special Industrial Power Rate
SP	Surplus Firm Power Rate
Supply System	Washington Public Power Supply System
TDLRIC	Time-Differentiated Long Run Incremental Cost Analysis
TVA	Tennessee Valley Authority
Transmission System Act	Federal Columbia River Transmission System Act of 1974
WNP	Washington Public Power Supply System Nuclear Plant
WSCC	Western Systems Coordinating Council
kWh	kilowatthour



Chapter I

Purpose and Need



I. Purpose and Need

A. Summary of Bonneville Power Administration Authority

The Federal Columbia River Power System is operated in a coordinated manner. The Federal dams are owned and operated by either the U.S. Army Corps of Engineers or the U.S. Bureau of Reclamation. It is these agencies that establish the physical constraints regarding reservoir levels to insure adequate flood control, irrigation, navigation, recreation, and power generation. Bonneville Power Administration (BPA), an agency of the U.S. Department of Energy (DOE), serves as the Federal electric power marketing agent in the Pacific Northwest. BPA markets hydroelectric power from 30 projects on the Columbia River and its tributaries, as well as thermal power and conservation it acquires from non-Federal interests in the region. BPA markets this power on a wholesale basis to electric utilities, Federal agencies, and a limited number of large industrial customers. In addition, BPA constructs and operates an electric transmission system and transmits (wheels) power over these facilities for other entities.

BPA's major responsibilities, including establishing the rates to be charged to BPA customers, are embodied in four Federal statutes: the Bonneville Project Act of 1937 (Project Act), the Flood Control Act of 1944 (Flood Control Act), the Federal Columbia River Transmission System Act of 1974 (Transmission System Act), and the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Regional Act). While a number of other acts and agreements influence BPA operations, these statutes identify BPA's mission. The Project Act established the agency and instructed BPA to set rates to recover all the costs associated with production, acquisition, and transmission of electric power and to recover the Federal investment in the Federal Columbia River Power System (FCRPS). The Bonneville Project Act directs that the rates be designed overall to ". . . encourage the widest diversified use of electric energy . . ." at the ". . . lowest possible rate . . . consistent with sound business principles." The Project Act requires that BPA review the adequacy of its power rates at least every 5 years and, if necessary, adjust them.

The Transmission System Act placed BPA on a self-financing basis. This Act gave BPA the authority to use its revenue to finance ongoing programs, as well as access to \$1.25 billion in borrowing authority for transmission system construction. The Regional Act provided an additional \$1.25 billion in borrowing authority for conservation and renewable resource loans and grants. It also expanded the usage of the original \$1.25 billion authorized under the Transmission System Act. This borrowing authority is now available to fund new programs for which the Administrator became responsible as a result of passage of the Regional Act.

1. Resource Pools and Rate Pools

The Regional Act reaffirmed previously established directives and expanded BPA's responsibilities, requiring BPA to recover costs incurred pursuant to the Act. The Regional Act altered both the process and substance of BPA's rate development activities. Prior to the Regional Act, BPA allocated costs from a single pool of resources which included the Federal Columbia River Power System (FCRPS) hydroelectric facilities, a portion of the

Trojan Nuclear Plant, a portion of the Hanford New Process Reactor, and two net billed nuclear plants and 70 percent of a third plant being constructed by the Washington Public Power Supply System (Supply System). BPA's rates were designed to recover all costs associated with these resources. This included the cost of operating and maintaining the FCRPS, the cost of purchase power, the cost of interest on and amortization of the Federal investment in the system, and the cost of repaying that portion of the construction costs at Federal reclamation projects that are beyond the repayment ability of irrigators and have been assigned by law to commercial power revenues. 1/

The Regional Act created three distinct resource pools for purposes of establishing rates, and expanded BPA's authority to extend service to all customer classes in the region. The first resource pool, the Federal base system (FBS), is defined by the Regional Act to include the FCRPS hydroelectric projects, the resources acquired by the Administrator under long term contracts in force on December 5, 1980, 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. Under the exchange program, BPA is to purchase, from each utility participating in the exchange, an amount of power equal to a prescribed portion of the participant's residential and small farm load at the average system cost of the participant. 2/ BPA then sells an equal amount of power to the exchanging utility at the rate charged BPA preference customers. Any cost benefit resulting from this exchange is to be passed through to the utility's residential and small farm consumers.

The third resource pool, the new resource pool, includes all new resources that are developed, purchased, or otherwise acquired by BPA that are not identified as FBS replacements.

The costs of each resource pool are allocated to particular classes of customers as specified by the Regional Act. For purposes of establishing rates, the costs of Federal base system resources are allocated to BPA's preference customers (defined as public body, cooperative and Federal agency customers within the Pacific Northwest) and the residential and small farm loads of the exchanging utilities. These loads are often referred to jointly as those comprising the 7(b) rate pool, after the enabling section of the Regional Act. If the Federal base system resources are projected to be insufficient to meet these loads, a sufficient portion of the exchange resource pool must be combined with the Federal base system resources to serve the 7(b) loads. The remaining exchange resources are used to serve BPA's direct service industrial (DSI) customer load. After DSI loads are served, any remaining exchange resources and new resources are used to serve load growth of the investor owned utilities (IOU's) and new large single loads of public bodies, cooperatives, and Federal agencies.

2. Fish and Wildlife Program

On November 15, 1982, the Northwest Power Planning Council (Council) adopted its Columbia Basin Fish and Wildlife Program (Program) pursuant to Section 4(h) of the Regional Act. The Program identifies problems and proposes measures for the protection, mitigation and enhancement of fish and wildlife resources in the Pacific Northwest. Problem areas identified

were (1) anadromous fish migration, survival and reproduction; (2) resident fish survival and propagation; and (3) the protection and enhancement of wildlife habitat and resources.

Prior to the adoption of the Program, BPA activities focused on basic research, habitat improvement, and radio-tracking of juvenile and adult salmon and steelhead. For fiscal years 1984 and 1985, BPA's activities will fall into four categories: (1) providing water flows as described by the Council's Program (including the Water Budget); (2) research and development; (3) habitat improvement; and (4) capital improvements. Collectively, these activities comprise the Fish and Wildlife Program.

The Fish and Wildlife Program affects BPA in two ways. First, BPA's overall revenue requirement includes recovery of the costs of research and development, habitat improvement, and approved major capital improvements as well as repayment of the Federal investment in structural changes in Federal facilities. Second, providing for the Council's Water Budget results in a reduction in the firm energy load carrying capability of the region's power system. The environmental effects of implementing the site-specific aspects of the Council's Program are beyond the scope of this EIS. The analysis in this document focuses on the effect on BPA's rates of implementing those aspects of the Program for which BPA has responsibility.

The Water Budget: Regulation of the Snake and Columbia Rivers through the development of hydroelectric facilities has greatly altered the natural flows in the Columbia River drainage. While this regulation has enhanced the ability of river managers to produce power, the altered flows and increased storage capability provided by the dams have created two negative conditions for migrating juvenile salmonoid: (1) reduced "flushing flows" that were naturally provided by spring runoff, and (2) resultant increased travel time for migration from area of origin to the ocean. These conditions have contributed heavily to increased mortality of migrating juvenile salmonoid.

To partially mitigate these effects, the Council created the Water Budget, a river management device consisting of the reservation and use of a block of water to assist spring downstream salmonoid migration. Potential use by the fisheries agencies and Indian tribes of the Water Budget is planned for the period between April 15 and June 15, beginning in 1984, and will result in an estimated reduction in the regions' firm energy load carrying capability from the Columbia River and its tributaries of 550 average megawatts, according to Council estimates (Council's Fish and Wildlife Program, section 304(a)(4), p. 3-5). There are a number of other estimates of power impacts based on other studies. However, none of these studies treat the flow requirements of the Water Budget in exactly the same way. As BPA, the Corps of Engineers, the Bureau of Reclamation, fishery agencies, and others gain experience in the implementation of the Water Budget, the exact effects it will have on the regional power system will become more apparent. BPA has initiated a separate environmental analysis on the systemwide power impacts associated with the Water Budget.

Research and Development: Continuing support for habitat improvement, radio-tracking, and development of new concepts in fish ladder design was provided by BPA in 1982. In fiscal years 1984 and 1985, research

and development activities will support a range of measures specified in the Council's Program as well as study of a number of system-oriented problems. These system-wide issues include: provision of sufficient water quality and quantity at and between projects; studies of migrational characteristics and their relationships to varying flows and river conditions; data collection on survival rates of migrating salmonoid; and studies of hatchery practices, including fish nutrition and diseases.

Capital Improvements: No capital improvements, such as major hatchery facilities, will be funded directly by BPA in fiscal years 1984 and 1985; nor is it likely that improvements greater than \$1,000,000 will be funded before FY 1985 because of actions and procedures which must be completed prior to construction (i.e., research and design, compliance with the National Environmental Policy Act of 1969, Regional Council approval, and cost-sharing negotiations).

Program Costs: Revenue to fund BPA's Fish and Wildlife research and development and habitat improvement projects is estimated to be \$23 million in FY 1984 and \$25 million in FY 1985. These amounts are part of BPA's proposed total revenue requirements for those years. The estimated overall rate impact to some customers from these portions of the Council's Program would be an increase of 0.2 mills per kilowatthour.

In terms of rate impacts, the most significant element of the Council's Program is the Water Budget. As previously indicated, implementation of the Water Budget, as defined by the Council, is projected to reduce the firm energy load carrying capability of the region's power system by approximately 550 megawatts (MW). For the initial rate proposal, the portion of this reduction associated with the Federal system is treated by BPA as a reduction in the megawatts of firm power available for sale. The estimate of reduction is based on the results of hydro regulation studies with targeted flows. The effect of providing for the Water Budget will vary depending on conditions in the river system relating to the balance between resources available for sale and customers.

The proposed revenue level alternative examined in this statement includes the estimated reduction in firm energy load carrying capability of the FCRPS that results from providing for the Water Budget beginning in fiscal year 1984. The effect of the Water Budget on BPA's initial rate proposal is analyzed in Chapter II.B.1.c.; the effect on BPA's customers and retail rates in Chapter II.B.3.c.; the effect on load/resource balance in Chapter IV.G.

B. History of BPA Rates

Until the 1970's, BPA rates were remarkably stable. The first wholesale power rates were implemented on June 8, 1938, and September 13, 1939, and included a firm power rate of \$17.50 net per year per kilowatt of billing demand with no energy charge. These rates remained in effect until 1965, when they increased 3 percent. BPA adjusted its wholesale power rates again in 1974 to increase revenues 27 percent.

A series of major rate increases began in 1979 when BPA raised transmission and wholesale power rates sufficiently to increase revenue

88 percent. This revenue increase was followed by a 78.5 percent increase in 1981 and a 58 percent increase in 1982. All of these rates have received final approval from the Federal Energy Regulatory Commission (FERC).

The recent dramatic increases in BPA's rates can be attributed primarily to costs for thermal resources from which BPA plans to acquire output to serve forecast load growth. Until the 1960's, regional hydroelectric resources provided nearly all of the power needed in the region. By that time, the potential for adding new hydroelectric resources for producing baseload energy was limited. BPA, therefore, began to acquire rights to the output of planned baseload thermal generating resources to meet forecast future loads. Because the cost of new thermal generation is much higher than the cost of existing hydro generation, the acquisition of this thermal power increased BPA's costs considerably. Inflation and high interest rates also contributed to cost escalation.

Table I-1 lists, for comparative purposes, the average firm power rates charged by Federal power marketing agencies.

TABLE I-1
Average Firm Power Rates of Agencies Marketing Federal Power, 1983

<u>Agency</u>	<u>Average Firm Power Rate</u>
Bonneville Power Administration	19.1 mills/kWh <u>a/</u>
Tennessee Valley Authority	40.6 mills/kWh <u>a/</u>
Southwestern Power Administration	12.9 mills kWh <u>a/</u>
Western Power Administration	6.0-21.4 mills/kWh depending on project (8 projects)
Alaska Power Authority	12.1-15.6 mills/kWh depending on project (2 projects)
Southeastern Power Authority	6.4 mills/kWh

a/ Assuming a 70 percent load factor and 10,000 kW load.

Source: Federal Energy Regulatory Commission staff and Tennessee Valley Authority staff, February 1983.

C. Rate Development Process

One of BPA's first steps in developing new rates is to prepare a Loads and Resources Study. This study projects the amount of firm load BPA will be required to meet and the resources available to meet that load. BPA also develops a Revenue Requirement Study which determines both BPA's revenue requirement and the adequacy of the existing rates to recover revenues sufficient to meet BPA's financial obligations. If expected revenues are not sufficient to meet BPA's revenue requirement, rates must be revised.

Once the Revenue Requirement Study has been completed and the need for revised rates has been determined, BPA develops a Cost of Service Analysis (COSA) and a Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis. The COSA identifies the average costs associated with providing service to each class of customer. From these allocations of costs, specific rates are designed in the Wholesale Power Rate Design Study (WPRDRS) to collect the necessary revenues given average water conditions. The TDLRIC Analysis is used to develop illustrative rates, to provide the basis for classification of certain costs between capacity and energy in the COSA and WPRDRS, and to identify the incremental cost of providing service during varying time periods in order to develop rates that may be differentiated on a seasonal, daily, and hourly basis.

The Cost of Service Analysis does not allocate costs to some classes of service. Consequently, in the WPRDRS adjustments are made to account for, among other things, revenue deficiencies related to fixed contracts, costs and revenues associated with the capacity/energy exchange, the value of reserves provided by DSI customers, excess revenues from nonfirm sales, equalization of demand charges, and, for certain utilities, a low density discount. Many of the adjustments made during the rate design process are intended to incorporate adjustments specified in the Regional Act, to reflect results of the TDLRIC Analysis, and to reflect BPA's rate design objectives which include environmental considerations.

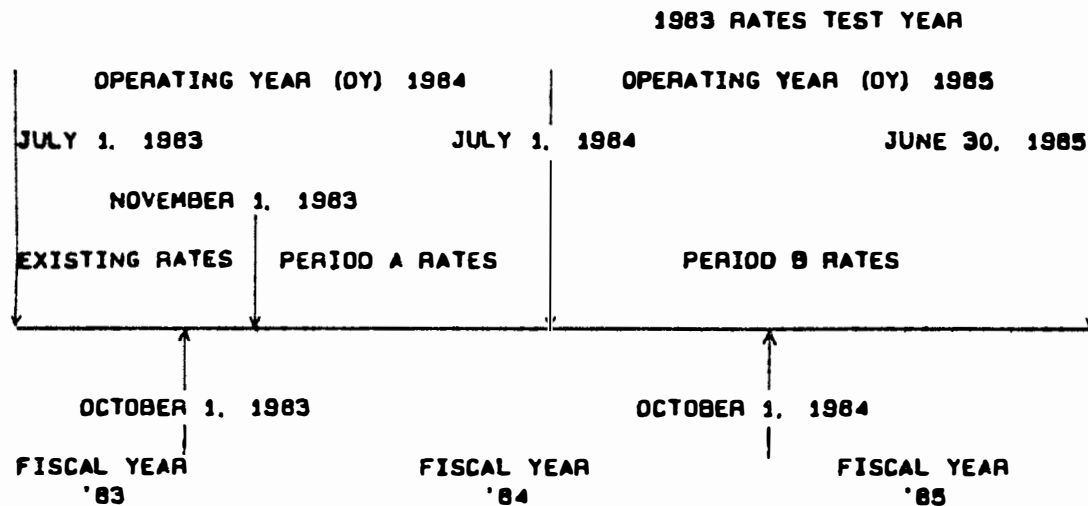
In developing rates, the basic rate design objectives BPA follows include: (1) revenue must be adequate to meet repayment obligations; (2) the revenue requirement must be met with the burden distributed in an equitable manner among recipients of the service; (3) rates should be designed to encourage conservation and to minimize environmental impact; and (4) rates should be designed to encourage efficient use of the power system by reflecting costs incurred and benefits received. Other factors include rate continuity, ease of administration, revenue stability, and ease of understanding.

D. Need for Action

BPA's Revenue Requirement Study prepared for the 1983 rate filing indicates BPA needs to increase wholesale power rates to meet its total financial obligations. BPA is planning to implement new rate schedules on November 1, 1983, which would be in effect through June 30, 1985. The rate schedules proposed by BPA include charges for two periods. Period A rates would be in effect for the last 8 months of BPA's operating year (OY) 1984, from November 1, 1983, to June 30, 1984. Period B rates would be effective for all of OY 1985, which extends from July 1, 1984, through June 30, 1985. Table I-2 illustrates the rate periods.

Preliminary forecasts indicate that BPA needs to recover \$4.6 billion in revenue during the rate period. Under current rates, revenue during the rate period would be \$3.9 billion, based on forecasted loads. Without a rate increase, BPA would incur a deficit of about \$7 billion.

TABLE I-2. BPA RATE PERIODS AND KEY DATES



THE RATE PERIOD FOR THE RATE CASE IS 20 MONTHS, FROM NOVEMBER 1, 1983 THROUGH JUNE 30, 1985. PERIOD A CONSTITUTES THE FIRST RATE PERIOD AND PERIOD B IS THE SECOND RATE PERIOD.

THE REVENUE REQUIREMENT FOR OPERATING YEAR 1984 IS BASED ON A WEIGHTED AVERAGE FORMULA (25 PERCENT OF THE COSTS OF FISCAL YEAR '83 AND 75 PERCENT OF THE COSTS OF FISCAL YEAR '84) OF THE RESULTS OF REPAYMENT STUDIES FOR THESE TWO FISCAL YEARS, FY '83 AND FY '84.

THE REVENUE REQUIREMENT FOR OPERATING YEAR 1985 IS BASED ON A WEIGHTED AVERAGE FORMULA (25 PERCENT OF THE COSTS OF FISCAL YEAR '84 AND 75 PERCENT OF FISCAL YEAR '85) OF THE RESULTS OF THE REPAYMENT STUDIES FOR THESE TWO FISCAL YEARS, FY '84 AND FY '85.

THE RATES FOR PERIOD B ARE DEVELOPED DIRECTLY FROM OPERATING YEAR 1985 REVENUE REQUIREMENT. THE RATES FOR PERIOD A ARE DEVELOPED, AS A AS A FIXED PERCENTAGE OF THE OPERATING YEAR 1985 RATES, SO THAT IN CONJUNCTION WITH THE EXISTING RATES, THE OPERATING YEAR 1984 REVENUE REQUIREMENT WILL BE MET.

NEW RATES WILL BE INITIATED ON JULY 1, 1985 AS MANDATED BY THE 1980 PACIFIC NORTHWEST POWER PLANNING AND CONSERVATION ACT.

A significant portion of the required revenue increase for the rate period is attributable to increased costs of the Washington Public Power Supply System (Supply System) Nuclear Projects 1, 2, and 3. Under net billing agreements, BPA is obligated to cover 100 percent of the costs for projects 1 and 2, and 70 percent of project 3. BPA's payments associated with the Supply System projects are estimated to increase from \$622 million in FY 1983 to \$759 million in FY 1984 and \$861 million in FY 1985. These include \$103 million in FY 1984 and \$157 million in FY 1985 in operating costs for project 2, scheduled to begin operating in February 1984.

Costs of power acquired by BPA through exchanges with utilities are estimated to increase from \$613 million in FY 1983 to \$858 million in FY 1984 and \$1.050 billion in FY 1985. These increases are primarily because a larger portion of residential and rural loads will be eligible to be served with exchange resources. The Regional Act provides that BPA increase its service to exchanging utilities from 70 to 80 percent of the exchanging utilities' residential and small farm loads beginning July 1, 1983, and to 90 percent on July 1, 1984. During the rate period, publicly owned utilities are expected to participate for the first time in the residential exchange as well as the Exchange Transmission Credit Agreement. The Exchange Transmission Credit Agreement would provide public agencies with transmission facilities the net benefit they would have received if they had participated in the residential exchange.

High interest costs have also contributed to BPA's need for increased revenue. Interest payments BPA must make are expected to increase from \$304 million in FY 1983 to \$350 million in FY 1984 and \$371 million in FY 1985.

BPA's expansion of the conservation programs, which are mandated by the Regional Act, will also increase BPA's costs. The expansion includes conservation programs in the residential and commercial sectors as well as programs focused on institutional buildings, industries, and state and local governments. Since the conservation programs are financed primarily from borrowing rather than from revenues most of the impact of these programs is reflected in the interest payments described above. In addition to the interest payments, BPA has allotted \$4 million in FY 1983, and will allot \$15 million in FY 1984, and \$24 million in FY 1985 from its revenue for supporting the conservation programs.

Authorized by the Regional Act, the Northwest Power Planning Council adopted a program to protect and enhance fish and wildlife along the Columbia River and its tributaries. Costs of this program are estimated to rise from almost \$10 million in FY 1983 to \$23 million in FY 1984 and \$25 million in FY 1985.

Higher costs are not the only factor contributing to BPA's need to increase rates. Revenue collected by BPA in FY 1983 is anticipated to be lower than had been forecasted when the FY 1983 rates were developed. The revenue deficiency is caused primarily by a decrease in BPA's loads and BPA's inability to sell surplus firm power at as high a rate as had been planned. In FY 1984 and FY 1985, BPA anticipates that loads will increase somewhat, but costs are increasing faster than is load growth, causing the unit cost of providing service to increase.

In order to meet its fiscal responsibilities (which include eliminating deficits and making planned amortization payments), BPA's Revenue Requirement Study reflects actual historic cash amortization, and assumes repayment of deferral plus all normal scheduled amortization by September 30, 1985. In addition, it reflects all of BPA's obligations under the Regional Act, including exchange costs. To assist BPA in meeting its repayment obligations, a cash lag adjustment has been added to the revenue requirement.

E. Responsibilities Under the National Environmental Policy Act of 1969

The National Environmental Policy Act of 1969 requires that environmental impact analyses be performed prior to arriving at decisions on major Federal actions that significantly affect the environment. BPA has prepared this environmental impact statement (EIS) to analyze the potential environmental effects of the proposed 1983 wholesale power rate increase.

BPA has also considered the cumulative impact which the current rate proposal may have in combination with wholesale power rate increases implemented on December 20, 1979, on July 1, 1981, and on October 1, 1982. These past rate increases, coupled with the proposed 1983 rate increase, could have significant environmental impacts. The Council on Environmental Quality's "Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act" instructs that the scope of BPA's environmental analysis include cumulative actions and their cumulative impacts.

F. Implementation Schedule

BPA's power sales contracts allow for revised rates to become effective after no less than 9 months' notice of the intent to revise rates. BPA announced its intent to revise its wholesale power rates in the Federal Register on January 28, 1983 (48 FR 4028), and published an initial proposal in the Federal Register on March 28, 1983 (48 FR 12777). A series of public and formal hearings enabled interested persons and parties to comment on the proposal. Written comments were also accepted.

The final rate proposal reflects the results of this EIS, as well as other information developed during the hearings and public comment period and used in the final BPA studies prepared for the rate filing. If approved by the Federal Energy Regulatory Commission on an interim basis, the proposed new rates would take effect on November 1, 1983.

G. Appeal Process From Administrator's Record of Decision

40 C.F.R § 1506.10 (1982) requires notice of a final EIS to be published in the Federal Register by the Environmental Protection Agency thirty (30) days before a decision can be made on the proposed action. However, 40 C.F.R § 1506.10 sets forth an exception to this publication requirement for decisions subject to a formal, internal appeal process.

The Regional Act established by statute such a formal, internal appeal process that allows other agencies and the public to appeal the Administrator's Record of Decision on BPA's 1983 Wholesale Power Rates.

The rates established by the Administrator's Record of Decision will only become effective upon confirmation and approval by the Federal Energy Regulatory Commission (FERC) (16 U.S.C. § 839e(a)(2)). The Regional Act provides that BPA rates are only effective upon a finding by FERC:

" . . . that such rates -

are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,

are based upon the Administrator's total system cost, and

insofar as transmission rates are concerned, equitably allocate the costs of the Federal Transmission System between Federal and non-Federal power utilizing such system."
16 U.S.C. § 839e(a)(2).

FERC review under the three enumerated standards of the Regional Act provides interested members of the public and governmental agencies with a real opportunity to alter the Administrator's rates decision. This review process is internal within the Department of Energy. The Department of Energy Organization Act of 1977, P.L. 95-91, established that both the FERC and Bonneville Power Administration are within the Department of Energy.

FERC regulations provide other agencies, and the public, with an opportunity to protest or intervene in final confirmation and approval proceedings concerning BPA rates. See "Confirmation and Approval of Rates of Bonneville Power Administration", 46 FR 60613 (1981) (to be codified at 18 C.F.R. § 300.10(a)(4)). These FERC intervention regulations grant the public broad rights to intervene and make their views known concerning final confirmation and approval of BPA's rates.

The Administrator's rate decision becomes final only upon confirmation and approval by FERC. FERC also has the only authority to approve on an interim basis the rates submitted by the Administrator (16 U.S.C. § 839e(i)(6)). FERC can approve, or disapprove, the final rates submitted by the Administrator on an interim basis, pending FERC's final confirmation and approval in accordance with the Regional Act (16 U.S.C. § 839e(i)(6)). FERC regulations governing interim acceptance and review of BPA rates explicitly provide that:

" . . . the Commission may take any of the following actions, based on an evaluation of the application:

(1) Order the rate schedule into effect on an interim basis, effective on the date requested by the Administrator or at such time as the Commission may otherwise order;

(2) Deny the Administrator's interim rate request and reject the application, if the Commission determines that the Administrator's application:

(i) Is patently deficient with respect to the filing requirements of this Part; or

(ii) Fails to comply with the applicable provisions of the Pacific Northwest Electric Power Planning and Conservation Act; or

(3) Deny the Administrator's interim rate request and review the application for final confirmation and approval of the rate schedule pursuant to the provisions of this part." "Confirmation and Approval of the Rates of the Bonneville Power Administration," 46 FR 60613 (1981) (to be codified at 18 C.F.R. § 300.20(b)).

If the Commission places a rate schedule filed by the Administrator into effect on an interim basis, such rates are subject to refund with interest (Supra, 18 C.F.R. § 300.20(c)). FERC regulations further provide that a notice of any action taken by FERC concerning the Administrator's request for interim rate acceptance will be published in the Federal Register and will be mailed to any interested persons identified in the Administrator's filing (Supra, 18 C.F.R. § 300.20(d)). The list of interested persons identified by the Administrator includes all parties to the 1983 Wholesale Power and Transmission Rate proceeding and all persons that have expressed an interest to BPA in its ratemaking proceedings and have supplied BPA with their addresses.

Any members of the public who desire to be intervenors before FERC in the final confirmation and review process, or the interim approval proceeding, must file a timely petition to intervene with FERC. The timing for filing such a petition to intervene will be triggered by the FERC publishing a Notice in the Federal Register of BPA's request for final confirmation and approval and interim approval. For exact time deadlines and contents of petitions, consult FERC's general regulations governing petitions to intervene.

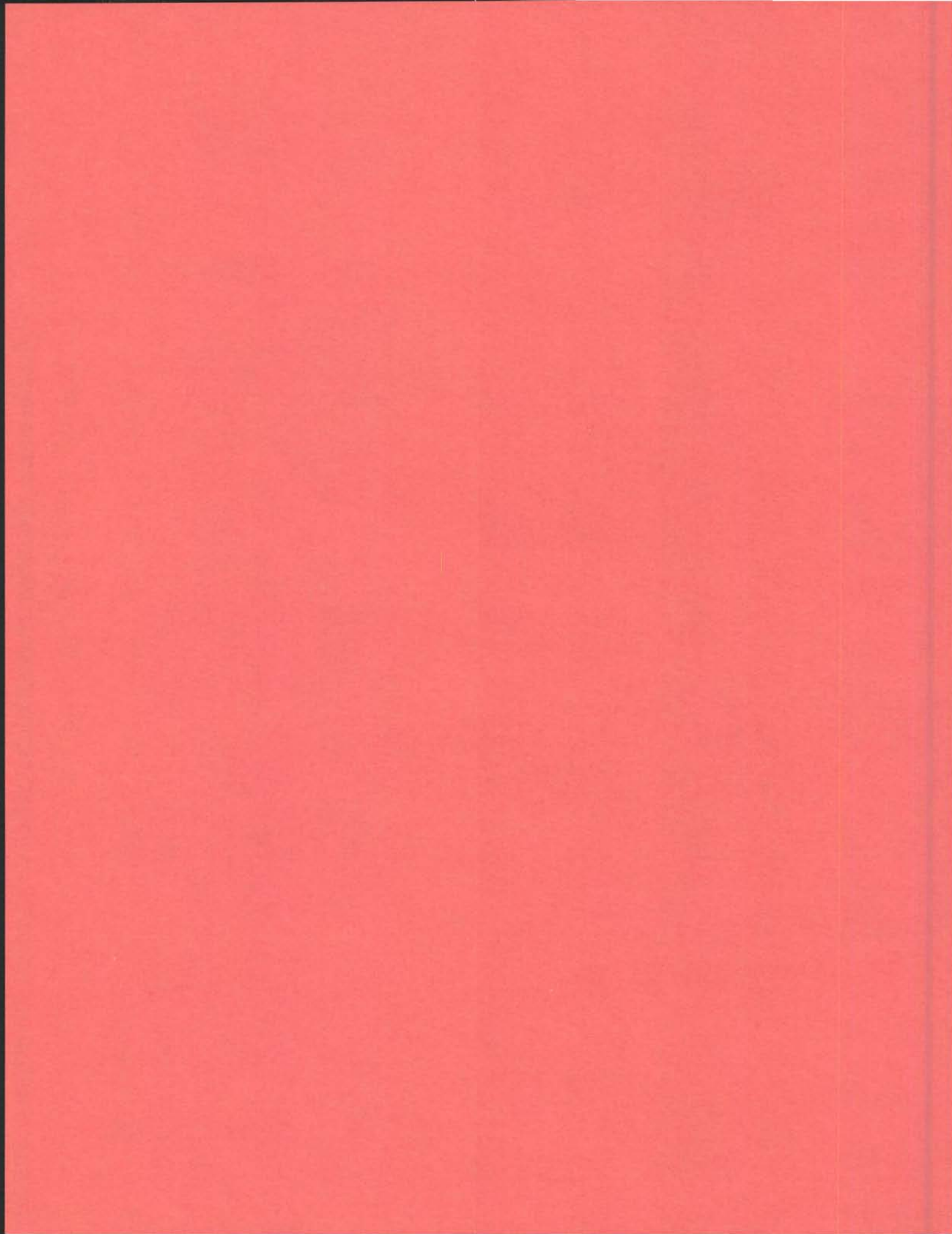
FOOTNOTES

1/ For a more detailed description of the repayment criteria in effect prior to the Regional Act see Final Environmental Impact Statement, Bonneville Power Administration, 1979 Wholesale Rate Increase, U.S. Department of Energy (DOE/EIS-0031-F), October 1979, pp. II-6 to 7.

2/ For a detailed discussion of the methodology for determining a utility's average system cost see Administrator's Record of Decision, Average System Cost Methodology, Bonneville Power Administration, U.S. Department of Energy, August 1981.

Chapter II

Alternatives Including the Proposed Action



II. Alternatives Including the Proposed Action

A. Introduction

This section of the statement presents the description of BPA's existing rates, proposed rates and reasonable alternative wholesale rate actions, and a comparative analysis of the environmental consequences of each. The alternatives and their expected environmental consequences are summarized in this chapter to enable the decisionmaker and the public to evaluate the comparative environmental merits of the alternatives. The analytical procedures used to identify the environmental consequences of the alternatives are discussed in detail in the Environmental Consequences chapter of this statement (Chapter IV).

The "Council on Environmental Quality (CEQ) Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act" instructs that the scope of an agency's environmental analysis include cumulative actions and their cumulative impacts (40 CFR 1508.25). BPA implemented sizeable wholesale rate increases on December 20, 1979, July 1, 1981, and October 1, 1982. BPA also foresees rate increases in July 1985, as well as this proposed increase for November 1983. Consistent with the CEQ requirement to address cumulative actions and impacts, this statement addresses alternative cumulative effects of BPA's 1979, 1981, and 1982 rate increases as well as the impacts of the proposed 1983 increase. BPA currently lacks sufficiently reliable projections of the July 1985 increase to permit a meaningful analysis of its probable cumulative contribution to the effects of prior rate increases.

The development of wholesale power rates involves two levels of decisions: (1) the revenue level needed to meet BPA's repayment requirement and (2) the structure of the rate design created to achieve the desired revenue level. Each level of decision requires a choice among alternatives. Therefore, the discussion of alternatives for the 1983 rate proposal is divided into sections addressing first alternative revenue levels and then alternative rate designs.

The discussion of alternative revenue levels for 1983 includes an analysis of the cumulative effect of rate increases from 1979-1983. The discussion also includes a description of several alternative revenue levels during the upcoming rate periods and comparisons of the revenue and environmental consequences of the alternatives. The consequences of the alternatives are summarized in a matrix. The discussion of rate design alternatives for the 1983 increase analyzes the designs of the existing and proposed rates and alternative rate designs and compares the consequences of all alternatives.

B. Alternative Revenue Levels

This section describes and compares the consequences of several alternative revenue levels, including BPA's proposed revenue level, for a November 1983 rate increase (i.e., for the rates which will be in effect from November 1, 1983, through June 30, 1985). While some of the alternatives discussed are outside the agency's current statutory authority, they are reasonable alternatives as defined by the CEQ regulations and their

examination provides appropriate comparative information on the consequences of a revenue increase. The alternatives considered are (1) Base Rate Alternative; (2) No Action Alternative; (3) Proposed Alternative; (4) Direct Financing Alternative; and (5) Long Run Incremental Cost Alternative.

1. Description of Revenue Level Alternatives

a. Base Rate Alternative

Following NEPA guidelines, BPA assesses the cumulative impacts associated with past, present, and anticipated future revenue level increases. December 20, 1979, was selected as the point to begin the cumulative analysis because it marks the date of the initial action in a series of substantial BPA revenue level increases. Figure II-1 shows both the actual cost and the real cost (i.e., the cost adjusted to remove differences due to inflation) of priority firm power, in 1980 dollars, from FY 1937 to FY 1983. As is evident from this figure, the real cost of power, measured against the Gross National Product Deflator Index, declined fairly steadily from 1937 to 1979 and then began a sharp increase. Consequently, the cumulative analysis focuses on the combined effects of rate increases implemented on or after December 20, 1979. By 1985, the real cost of power is still projected to be slightly less than what it was in 1937 (in 1980 dollars, 16.20 versus 16.75 mills per kilowatthour, respectively).

The base rate alternative assumes that BPA "froze" the rates that went into effect on December 20, 1974. With the rates remaining constant, revenue levels increase only as load increases. This approach establishes what would have happened had BPA taken no rate actions to increase revenue subsequent to 1974.

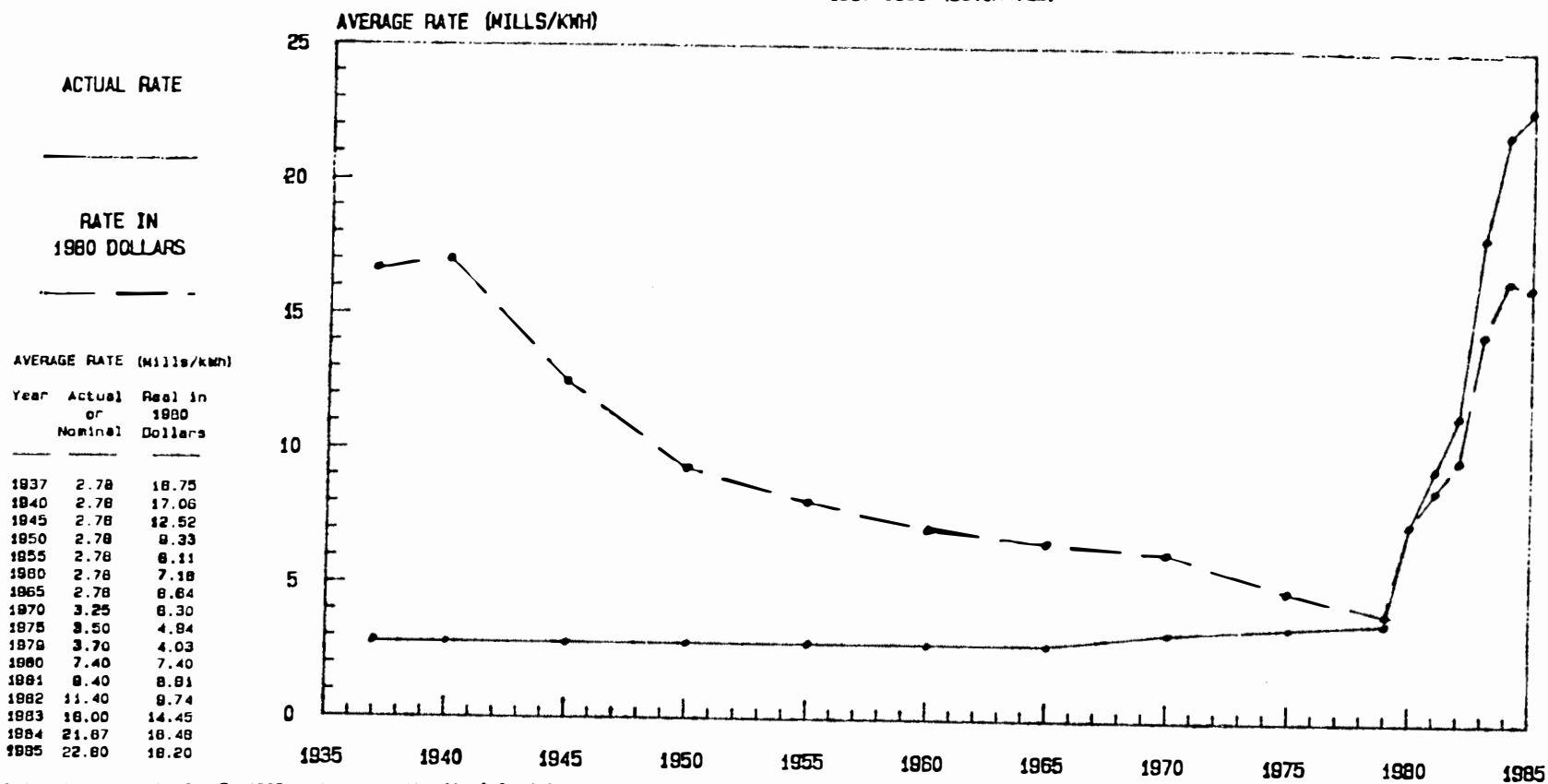
Under base rate assumptions, loads from 1979 through 2000 would have been higher than under any of the other revenue level assumptions. In the absence of any rate increases, inflation would have diminished the real cost of power since 1979. The consumer demand response to price increases resulting from historical wholesale power increases since 1979 and any future increases would not have occurred. Based on BPA's Energy Model forecast for this study, FY 2000 BPA loads under base rate assumptions would be 8 percent higher than under BPA's current rates and 10 percent higher than under proposed rates. However, despite the higher loads, this alternative results in a lower revenue amount than any of the other alternatives, and BPA would collect far less revenue than would be required for repayment.

b. No Action Alternative

Under the no action alternative, the existence of historic rate increases is assumed. It is also assumed that BPA would maintain its present rate structure (rates effective on an interim basis as of October 1, 1982) throughout the period of analysis, resulting in a forecast revenue level of \$3.893 billion for the rate period November 1, 1983, through June 30, 1985, given forecast loads. This compares to BPA's revenue needs for this rate period of approximately \$4.6 billion identified by BPA's initial studies.

FIGURE II-1: BPA WHOLESale PRIORITY FIRM RATES

1937-1983 (ESTIMATED)



Note: Average rate for FY 1983 is based on the final load forecast used in BPA's 1982 rate filing. Figures for FY 1983-1985 are estimated, based on a Gross National Product deflator series. 1985 is based on the full fiscal year.

c. Proposed Alternative

The proposed revenue alternative would collect revenue of \$4.6 billion. This would be sufficient to meet BPA's rate period revenue requirement. This would be an overall revenue increase of 19 percent over the estimated revenue that would be collected under the present rates during the rate period. Since specific revenue increase impacts on individual customers or customer classes also reflect cost allocation and rate design actions, the average rate increase to a specific customer class may be somewhat different than the overall percentage increase.

The proposed alternative includes provision for the Council's "Water Budget," which is water set aside in order to provide for adequate river flow to aid downstream migration of fish (also see Sections I.A.2, II.B.3.c.(1)(a) and (b)). Inclusion of the annual Water Budget is handled as a megawatt reduction in hydro firm generating capabilities under critical water. Under conditions of sufficient surplus, BPA's costs remain essentially unchanged by the Water Budget, although a reduction occurs in the potential to generate revenue from surplus firm power sales. In times of power deficits, BPA may have to purchase high cost replacement resources to cover this loss in firm generating capability. In either case, the loss of inexpensive firm hydropower results in an increase in BPA's average cost of generation.

The water set aside to provide for the Water Budget may be available to generate secondary power, some portion of which will be marketable. The revenue from these sales has been credited to BPA's revenue requirement in the case of the proposed alternative. This revenue credit will partially offset the higher average resource costs for firm generation. The proposed Priority Firm rate includes an increase of approximately 0.5 mill per kilowatthour to cover the cost of providing for the Regional Council's Water Budget. The Industrial Firm Power rate may include a decrease of a currently undetermined amount because of a reduction in unrecovered surplus exchange costs that would have been allocated to the DSI's.

d. Direct Financing Alternative

Under the direct financing alternative, BPA would finance completion of Supply System plant number 2 and maintain the construction schedule for completion of plant number 3 in 1986 through revenues rather than bond issues. This results in an increase in BPA's revenue requirement. All other assumptions in this alternative are identical to the proposed alternative.

BPA's net billed share of Supply System plants 1, 2, and, 3 are FBS resources. Therefore, additional rate period costs associated with direct financing of remaining construction costs of plants 2 and 3 would be assigned to the rate pools served by FBS resources. The primary impact of this increased revenue level alternative will be on the Priority Firm rate.

e. Long Run Incremental Cost (LRIC) Alternative

Rates based exclusively on long-run incremental cost (LRIC) price wholesale power at the cost of acquiring new resources in the

Pacific Northwest. LRIC rates give potential consumers information on the social cost of providing an extra unit of electricity, and thus allow consumption decisions that yield an efficient allocation of resources between electricity and other goods and services. This efficient allocation is based on several assumptions, among them that all substitute goods are priced at their respective marginal social costs. In the Pacific Northwest, the primary substitutes for electricity are natural gas, wood, and various conservation measures, and to a much lesser extent, coal and renewables other than wood.

BPA has completed an updated Time-Differentiated Long Run Incremental Cost (TDLRIC) Analysis (available through BPA's Public Involvement Office) as part of its 1983 rate development process. The results of this study indicate marginal costs of \$54.71 kW/yr for capacity and 34.29 mills per kilowatthour for energy. Wholesale rates based on these costs would result in a decrease in total loads as users of electricity respond to higher power costs by cutting back on their electricity consumption. BPA's Energy Simulation Model estimated FY 2000 total loads under the LRIC alternative at 17 percent less than the loads under the proposed alternative and 18 percent less than the loads under the no action alternative. Despite the smaller loads, LRIC pricing would recover revenue in excess of BPA's total revenue requirement for the rate period.

2. Comparison of Revenues Recovered

Table II-1 summarizes the comparison of the revenue impacts of the alternatives. Under the base rate alternative, the revenue shortfall would increase throughout the period of analysis to the year 2000. This assumes that the rate is held constant from December 20, 1974, onward. The base rate alternative significantly undercollects revenue that is necessary to cover BPA's financial obligations for all the subsequent years. The base rate alternative, therefore, would consistently violate BPA's statutory requirement to collect revenue sufficient to meet present costs. It would also render BPA financially insolvent, and require development of a mechanism to recover from future ratepayers funds to meet this increasing shortfall.

The no action alternative would also result in serious revenue deficiencies, providing only 85 percent of the revenue necessary during the upcoming rate period. This revenue shortfall would have to be added to revenue required during subsequent repayment periods to allow BPA to meet its long-term financial obligations. The no action alternative would violate BPA's statutory requirement to be self-financing, since the agency would not fully cover all financial obligations.

The proposed alternative should provide sufficient revenue to meet BPA's rate period repayment requirement. Provided load forecasts are accurate, this alternative would not create the problems of under or overcollecting revenue. This alternative allows BPA to meet all financial obligations.

The direct financing alternative should provide sufficient revenues to meet BPA's rate period requirement if the decision was made to finance completion of Supply System plants 2 and 3. Provided load forecasts are accurate, this alternative would not create the problems of under or overcollecting revenue.

TABLE II-1
REVENUE LEVEL COMPARISON

Line No.	Criteria	A Base Rate	B No Action (Existing Rates)	C Proposed	E Direct Financing	D LRIC
1.	Meet BPA Statutory Requirements	No	No	Yes	Yes	No
2.	Meet all Required Financial Obligations	No	No	Yes	Yes	Yes

The revenue level based on LRIC pricing would yield revenue significantly in excess of BPA's repayment requirement for the rate period and all years for the foreseeable future. Setting the revenue level based on LRIC pricing, however, may violate the Congressional directive in the Bonneville Project Act "to encourage the widest diversified use of electricity" at the "lowest possible rate . . . consistent with sound business principles." While collection of revenues in excess of BPA's revenue requirement may be "consistent with sound business principles," the "lowest possible rate" is a lower rate level at which BPA can provide service to its customers while simultaneously meeting its repayment requirement. A LRIC based revenue level would more than enable BPA to meet all financial obligations.

3. Environmental Consequences of the Alternatives

The alternative revenue levels have varying consequences for the physical and the socioeconomic environments. These potential primary impacts are outlined in Table II-2. This table consists of a matrix assessing the base rate, no action, proposed, direct financing, and LRIC alternatives.

As the matrix demonstrates, the base rate alternative has the most negative impact on air quality due to increased amounts of required thermal generation relative to the other alternatives. The negative impacts to water quality and quantity associated with irrigation would be least under the base rate alternative, due to the lower amounts of conversion to nonsprinkler irrigation methods under this alternative. However, an additional negative impact to water quality and quantity not illustrated in the matrix would be expected under base rate assumptions. The amount of additional small hydro which would be required by the year 2000, while equal to that required under the no action alternative, would be greater than under the proposed, direct financing, and LRIC alternatives. Correspondingly, the comparatively lower levels of impacts to water quality and quantity from irrigation under the base rate alternative would be offset by higher levels of impacts associated with larger amounts of small hydro generation. Meanwhile, the base rate alternative would result in the most beneficial short term impact to the socioeconomic environment, since it reflects the lowest rate level among the alternatives.

The LRIC alternative would result in the most positive effect on the physical environment, since the fewest amount of generating resources would be needed to serve the region's electric loads. However, the level of impacts to water quality and quantity attributable to irrigation would be greatest under this alternative. In the short term, the LRIC alternative would be expected to result in the most negative effects on the socioeconomic environment, since it reflects the highest rate level among the alternatives. The impacts of the direct financing alternative, proposed alternative and the no action alternative fall within the ranges defined by the base rate and LRIC alternatives.

In addition to the primary impacts, the alternative revenue levels will have secondary impacts associated with the construction and operation of power plants. These impacts include employment (level and compositions), land use, public facilities and service, and government costs and expenditures.

a. Effects on Demand for Electricity

An increase in the price for electricity will result in a decrease in the consumption of electricity. Based on BPA's Energy Simulation Model, the projected effect of each revenue alternative on electricity consumption by the years 1990 and 2000 is presented in Table II-3. Consumption in the years 1990 and 2000 was selected to demonstrate estimated short and long run price effects, respectively.

The lowest load occurs under the LRIC pricing alternative. Regional load requirements in the year 2000 would be 32,484 GWh's less under the LRIC alternative than under the no action loads under the Direct Financing alternative would be 6,539 GWh's less than under the no action alternative. The proposed revenue level alternative would result in a load that is 2,941 GWh's lower than that under the no action alternative. The cumulative effect of the base rate alternative by the year 2000 is a load that is 17,992 GWh's more than the proposed alternative.

These differences in electricity consumption are the result of a combination of consumer responses to price, including conservation, curtailment, and conversion to alternative energy sources. Based on forecast results obtained from BPA's Energy Simulation Model during analyses performed for the 1983 initial rate proposal, approximately 84 percent of the difference in electricity consumption under the no action and proposed alternatives in FY 2000 would be based on conservation. The remaining 16 percent is accounted for by fuel switching. About 88 percent of the difference between the LRIC and no action alternative would be due to conservation and 12 percent to fuel switching.

TABLE 11-2
COMPARATIVE ANALYSIS OF IMPACTS OF REVENUE LEVEL ALTERNATIVES:
FY 1990 AND FY 2000

Item No.	Revenue Level	A	B	C	D	E	F	G
		<u>Need for Generation</u>	<u>Conservation and Curtailment</u>	<u>Fuel Switching (10¹² BTU's)</u>	<u>Effects on Irrigated Agriculture</u>	<u>Irrigation Effects of Water Quality/Quantity</u>	<u>Air Quality</u>	<u>Average Priority Firm Power Rates (mills/kWh)</u>
8-II	1. Base Rate	1990 Load = 169,148 GWh; Plant capacity = 1,961 MW more than No Action; 2000 load = 197,017 GWh; Plant capacity = 2,391 MW more than No Action.	Decrease in conservation from No Action case of 8,996 GWh in 1990, and 14,169 in 2000.	Percent change in consumption relative to No Action by fuel type: Oil = .8 Gas = -1.0	Percent increase relative to No Action in irrigated acreage in 2000 = .1; Percent increase in pumping load = 2.9	Percent decrease in water diversion = 7. Stream siltation and chemical contamination from irrigation would be less than under No Action.	Amount(tons) by which base case impact would be increased in 2000: particulates = 15,767.8; SO ₂ = 19,014.0; NOx = 21,546.6; hydrocarbons = 816.2; CO = 2,406.4; other = 7,339.4	FY's 81-2000, 3.7.
	2. No Action (Base Case)	1990 Load = 159,753 GWh; 2000 Load = 181,966 GWh;		Regional consumption by fuel type in 2000: Oil = 63.84 Gas = 357.45	Number of acres under irrigation in 2000 = 8.216 million; Irrigation pumping load in 2000 = 4,348 GWh.	Water diversion for irrigation in 2000 = 24.603 million-acre feet; some stream siltation and chemical contamination from irrigation.		FY 81, 7.8; FY 82, 11.4; FY's 83-2000, 18.0.
	3. Proposed	1990 Load = 157,439 GWh; Plant Capacity = 206 MW less than No Action; 2000 load = 179,025 GWh; Plant Capacity = 1,607 MW less than No Action.	Increase in conservation over No Action of 1,998 GWh in 1990, and 2,478 GWh in 2000.	Percent increase in consumption over No Action by fuel type: Oil = 0.0 Gas = .5	Percent decrease in irrigated acreage relative to No Action case by 2000 = 0; Percent decrease in pumping load = 0.	Percent increase in water diversion = 0. Chemical contamination and stream siltation due to irrigation approximately the same as in No Action.	Amount (tons) by which base case impact would be reduced in 2000: particulates = 8,003.0 SO ₂ =9891.9; NOx=11,209.4; hydrocarbons = 424.6; CO=1,251.9; Other = 3818.2.	FY 81, 7.8 FY 82, 11.4; FY 83, 18.0; FY 84-22.4; FY's 85-2000, 22.8.

TABLE 11-2 (Continued)

Item No.	Revenue Level	A Need for Generation	B Conservation and Curtailment	C Fuel Switching (10 ¹² BTU's)	D Effects on Irrigated Agriculture	E Irrigation Effects in Water Quality/Quantity	F Air Quality	G Average Priority Firm Power Rates (mills/kWh)
4.	Direct Financing	1990 Load = 155,780 GWh; Plant capacity = 368 MW less than No Action; 2000 load = 175,427 GWh; Plant capacity = 2662 less than No Action.	Increase in conservation over No Action of 3,633 GWh in 1990, and 6964 GWh in 2000.	Percent change in consumption over No Action by Fuel type: Oil = - 5.7 Gas = .6	(Direct Financing alternative not included in Irrigation Study)	(Direct Financing alternative not included in Irrigation Study)	Amount of reduction from base case in 2000: Particulates = 8,003.0; SO ₂ = 9,891.9; NO _x = 11,209.4; hydrocarbons = 424.6; CO = 1,251.9; Other = 3,818.2	FY 81, 7.8 FY 82, 11.4; FY 83, 18.0; FY 84, 25.4 FY's 85-2000, 26.6.
5.	LRIC	1990 Load = 131,416 GWh; Plant Capacity = 1,000 MW less than No Action; 2000 Load = 149,482 GWh; Plant Capacity = 5,129 MW less than No Action.	Increase in conservation over No Action case of 25,814 GWh in 1990 and 28,642 GWh in 2000.	Percent increase in consumption over No Action by fuel type Oil = .1 Gas = 3.7	Percent decrease in irrigated acreage in 2000 = .1; Percent decrease in pumping load = 8.5.	Percent Increase in water diversion = 2.5. Greatest increase in impacts associated with chemical contamination and stream siltation.	Amount of reduction from base case in 2000: Particulates = 8,003.0; SO ₂ = 9,891.9; NO _x = 11,209.4; hydrocarbons = 424.6; CO = 1,251.9; Other = 3,818.2	FY 81, 7.8; FY 82, 11.4; FY 83, 18.0; FY 84-40.5; FY's 85-2,000, 42.6.

TABLE II-3
ESTIMATED REVENUE LEVEL IMPACT
ON REGIONAL ELECTRIC SALES a/

Line No.	Revenue Level	A Year 1990		B Year 2000	
		Load (GWh)	b/	Load (GWh)	b/
1.	Base Rate	169,148		197,017	
2.	No Action	159,753		181,966	
3.	Proposed	157,439		179,025	
4.	Direct Financing	155,780		175,427	
5.	LRIC	131,416		149,482	

a/ Projections from BPA's Energy Simulation Model, March 1983.

b/ A gigawatthour (GWh) equals 10^6 kwh.

As Table II-4 demonstrates, the LRIC alternative would encourage the most significant increase in the estimated consumption of natural gas by regional utility customers. In the year 2000 under LRIC pricing of electricity, natural gas consumption would be approximately 3 to 5 percent greater than under the other alternatives. Under all alternatives, there is a general decline in the use of fuel oil through FY 2000. For both FY 1990 and FY 2000, electricity consumption is projected to be 18 percent less under the LRIC alternative than it would be under the no action alternative. This assumes consumers respond to higher prices with curtailment actions, fuel switching, and increasingly greater investments in conservation.

TABLE II-4
ESTIMATED REGIONAL ELECTRICITY, GAS, AND OIL
CONSUMPTION BY SECTOR IN BTU EQUIVALENTS
(10^{12} BTU'S)

Line No.	Revenue Level Alternative	A	B	C	D	E	F
		Year 1990			Year 2000		
		Electricity	Gas	Oil	Electricity	Gas	Oil
1.	Base Rate	577.13	343.83	73.40	672.22	353.92	64.36
2.	No Action	545.08	345.69	72.90	620.87	357.45	63.84
3.	Proposed	537.18	346.86	72.81	610.83	359.06	63.81
4.	Direct Financing	531.52	349.71	70.04	598.56	359.63	60.21
5.	LRIC	448.39	357.18	70.02	510.03	370.50	63.90

b. Effects on Need for New Generation

Over time, increases in the price for electricity and corresponding decreases in the growth of demand for electricity will limit the regional need to add new generation resources to the regional resource base. Estimates of the change in demand for generation that would result by the years 1990 and 2000 from each of the revenue alternatives are presented in Table II-5. These estimates were based on output from BPA's Least Cost Resource Mix Model (BPA 1982lm).

As indicated in Table II-5, the proposed, direct financing, and LRIC alternatives would require about 206, 368, and 1,000 fewer megawatts, respectively, of plant capacity in 1990 than would the no action alternative. The base case alternative would require 1,961 more MW of resources than the no action alternative. In the year 2000, the base rate alternative would require 2,391 more megawatts of capacity than would the no action alternative. The proposed alternative, direct financing alternative and LRIC alternative would result in 1,607, 2,662 and 5,129 fewer megawatts, respectively, in comparison to the no action alternative.

TABLE II-5
DIFFERENCE IN RESOURCE CAPABILITY REQUIRED UNDER NO ACTION
REVENUE ALTERNATIVE RELATIVE TO OTHER REVENUE ALTERNATIVES

Line No.	A	B	C
	Revenue Alternative	Year 1990 Resource Requirement (MW of capacity)	Year 2000 Resource Requirement (MW of capacity)
1.	Base Rate	1,961	2,391
2.	No Action	(0)	(0)
3.	Proposed	-206	-1,607
4.	Direct Financing	-368	-2,662
5.	LRIC	-1,000	-5,129

The additional capacity required under the no action, direct financing and proposed alternatives, over and above that required for the LRIC alternative, is assumed to be met by a combination of conservation, cogeneration, large thermal, geothermal, and small hydroelectric plants. There might be increases in the use of other generation resources, such as wind generation. All else equal, however, the greater the reduction in the rate of load growth, the lesser the need for all resources including renewables. For further discussion regarding the impacts of electricity price on regional generation resources see BPA, 1982k, Chapter V(B); BPA, 1981b, Chapter III (B)(2)(c); BPA, 1979b, Chapter IV(C) and (D).

c. Effects on Consumers

(1) Effects on Retail Rates

BPA cannot predict the exact impact of its revenue level on the retail rates of its utility customers. The effects on a utility's retail rates depend on many factors including (1) the amount of power purchased from BPA; (2) total operating costs; and (3) retail rate design. One utility may choose to increase its retail rates across the board regardless of customer class. Others may target the rate increase to a specific customer class. Other utilities may choose to alter their rate designs to encourage greater efficiency.

Regardless of specific utility decisions, a BPA wholesale rate increase will increase the operating costs of the utilities purchasing from BPA. To illustrate this impact, both the wholesale cost of BPA power and the retail residential rates of public and investor owned utilities, as projected by the BPA Supply Pricing Model in a 1982 forecast for the years 1981 through 1990, are shown in Figure II-2.

This chart highlights several findings. First, the general stability of the retail residential rates of the investor owned utilities over this ten year period is based primarily on the fact that these customers possess their own generating units. Second, the significant decline in their retail rate from 30.8 mills to 24.7 mills between fiscal years 1981 and 1982 is based on the effect of the the implementation of the BPA residential exchange program which allowed investor owned utilities' residential and farm customers to benefit from power purchased from the Federal base system. Third, the general stability of the residential rates of public agency customers between fiscal years 1983 and 1990 is based on the anticipated stability of the wholesale priority firm rate during this same period. A majority of the annual nonoperating costs of the net-billed Supply System plants entered the Priority Firm rate in the three fiscal years, 1981-1983, necessitating the significant rate increases of this period.

Under the forecast in constant 1980 dollars for Fiscal Year 1984 with a projected BPA wholesale rate of 15.3 mills per kWh, the public average retail rate is projected to be 25.4 mills per kWh with the IOU average retail rate being 27.7 mills per kWh. During FY 1984, wholesale power costs are forecast to account for about 60 percent of the public residential rate and about 55 percent of the private residential rate. As the wholesale rate increases in constant dollar terms, so does the percentage of retail residential rates accounted for by wholesale power costs. For FY 1990, the wholesale priority firm rate was forecast (in constant 1980 dollars) at 18.2 mills per kilowatthour; 69 percent of the public rate of 26.5 mills per kilowatthour and 59 percent of the private rate of 30.9 mills kilowatthour.

To the extent that a BPA revenue level increase is reflected in either BPA's priority firm or new resources firm rates, it will have an effect on the retail rates of investor-owned utilities (IOU's), insofar as such utilities participate in the residential and small farm exchange or purchase from the new resources pool. Under the provisions of the Regional Act, BPA is currently required upon request to make sufficient power available under the exchange program to serve 70 percent of the residential

and small farm loads of exchanging utilities at the rate charged BPA's preference customers. The percentage of load which may be exchanged increases by 10 percent annually until July 1, 1985, after which the IOU's can exchange 100 percent of this load. Cost benefits from the exchange must be passed through to the utilities' residential and small farm customers. This Regional Act provision has helped to hold down the retail rates of residential and small farm customers served by participating IOU's since 1981 when the exchange was first implemented.

If BPA were to implement the LRIC revenue alternative, the increase in the retail rates of the exchanging IOU's would be greater. However, the provision in the exchange contract which allows exchanging utilities to deem their average system cost equal to the Priority Firm rate limits the effect that increases in the Priority Firm rate can have on the exchanging utilities' retail rate. Once the Priority Firm rate exceeds an exchanging utility's average system cost, the exchange is effectively discontinued, and the utility's residential and small farm rates will be based on the cost of its own resources rather than the Priority Firm rate. It is expected that during OY 1985, three of the eight exchanging IOU's will be "deemers."

The increase in the proposed November 1983 (July 1984) Priority Firm rate is projected to be about 22 (27) percent. Increases in the proportion of IOU load eligible for Priority Firm service will partially offset the upward effect of the Priority Firm rate increase on IOU costs.

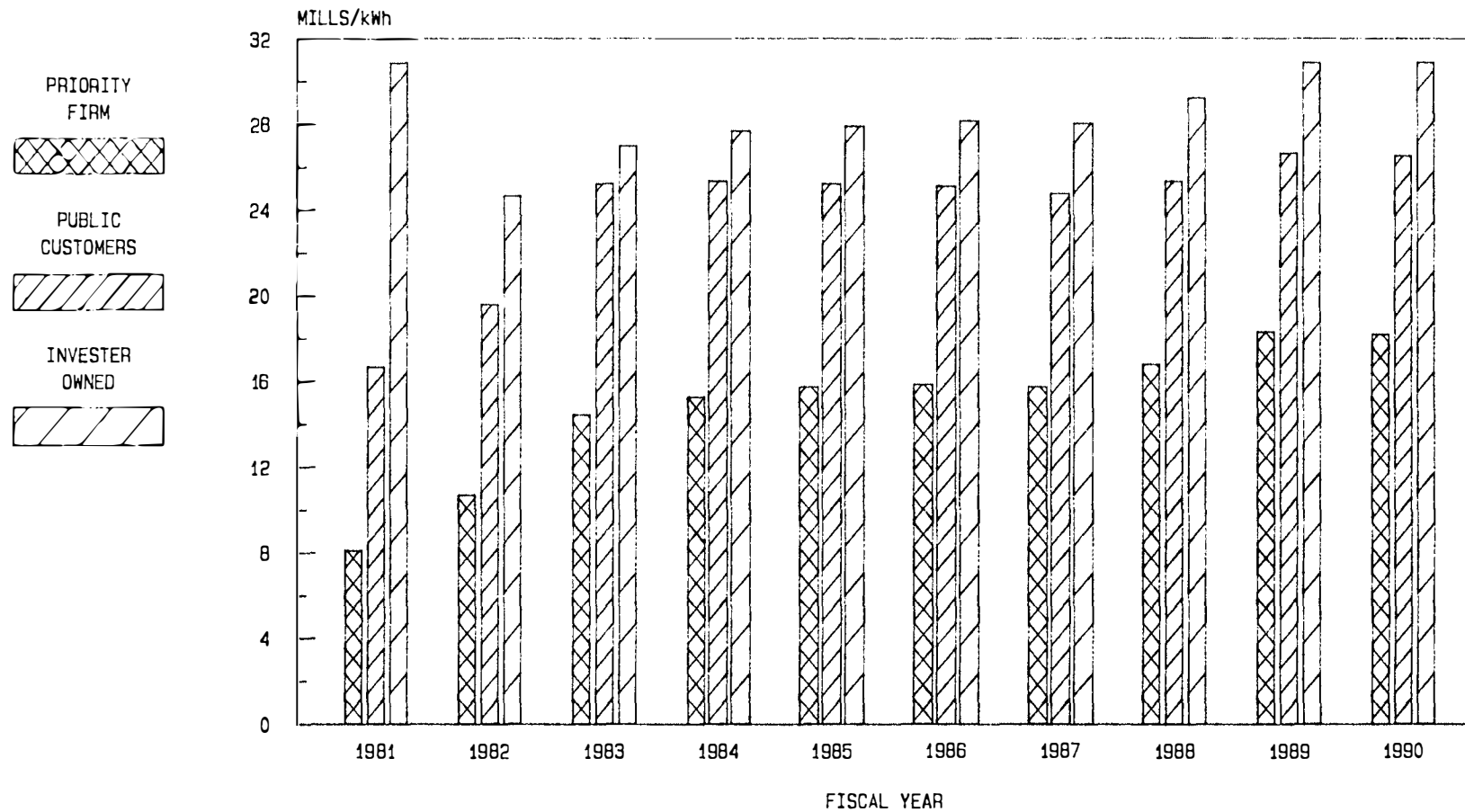
In addition to priority firm purchases, investor-owned utilities may purchase firm power from new resources under the New Resources Firm Power (NR) rate. Under the current proposal, the average NR rate for OY 1985 is projected to be 1.4 percent higher than the current average NR rate.

Preference utilities (i.e., cooperatives, municipalities, and public utility districts) will share in the cost of providing for the Regional Council's Water Budget (see Section I.A.) in three ways. The primary effect will be from the resulting increase in wholesale power rates (see II.B.1.c.). The increase in wholesale power rates will, in turn, affect the retail rates charged by the preference utilities.

The Water Budget will also affect preference customers who have their own hydrogeneration facilities located in the Columbia basin. Both Federal and non-Federal dams would have to use a portion of their firm energy capability in a noneconomic way. This reduction of a preference utility's firm energy capability could cause an increase in the amount of firm energy that they purchase from BPA, presumably at a higher cost than that associated with operation of their hydro resources. Therefore, the increase in load supplied by BPA could increase the retail rates charged by the preference customers. For the upcoming rate period, the effects of providing for the Water Budget are anticipated to increase the retail rates

FIGURE II-2: FORECAST OF WHOLESALE/RETAIL RATES

BASE CASE IN CONSTANT 1980 DOLLARS



charged by preference customers. For generating public utilities, the increase is projected to be less than the Water Budget induced increase in the Priority Firm rate (approximately .5 mill per kilowatthour). The projected increase is lower because some of their generating resources will be unaffected by the Water Budget, e.g., thermal or non-Columbia Basin sited hydroelectric. The nongenerating public utilities are projected to have rate increases close to the Water Budget induced Priority Firm rate increase of approximately .5 mill per kilowatthour.

IOU's will share in the cost of providing for the Regional Council's Water Budget (see Section I.A.2). Similar to the preference utilities discussed in the previous section, IOU's will face increased wholesale power rates. Any power purchased under exchange provisions will be at a higher rate. IOU's with their own hydroelectric facilities within the Columbia basin will also experience an increase in the firm energy generation portion of their average system costs. If an IOU has to purchase firm energy to replace a portion of its hydro capability, their cost of power will also increase. For the upcoming rate period, the effects of providing for the Water Budget are anticipated to increase the average retail rates charged by IOU's. The increase is projected to be less than the Water Budget induced increase in the Priority Firm rate of approximately 0.5 mill per kilowatthour. The projected increase is lower because the IOU's are able to serve large portions of their loads with resources unaffected by the Water Budget; e.g., thermal or non-Columbia basin sited hydroelectric.

Provision for the Water Budget has another rate impact which affects all priority firm purchasers as well as customers purchasing industrial firm power. To the extent that the Water Budget increases the average system costs of exchanging utilities, it increases the cost of BPA's exchange resources. Under the current proposal these costs are allocated to both the 7(b) and 7(c) rate pools. Countering this effect on the DSI rate is a decrease in unrecovered surplus exchange costs allocated to the DSI's. This decrease would occur from increases in the Priority Firm rate to reflect Water Budget costs, thereby decreasing the differential between the costs of exchange resources and the revenues collected under the Priority Firm rate from participants in the exchange.

Effects on the Pacific Southwest Utilities:

Increases in BPA revenue levels may result in impacts to Pacific Southwest utilities. These impacts would be concentrated in California, which accounts for the vast majority of BPA transactions with the Pacific Southwest region.

The proposed, direct financing, or LRIC revenue levels would be expected to result in higher retail rates of purchasing utilities in the Southwest than would result under the No Action alternative. These utilities may either purchase approximately the same amounts of BPA surplus energy and capacity at the higher rates, or displace a portion of these purchases with other alternatives which may become economically attractive as a result of BPA rate increases. These alternatives could include purchases from other sources in the Pacific Northwest or the Pacific Southwest, or continued operation of the utilities' own generating resources. In any event, higher BPA revenue levels, with higher corresponding rates for BPA's surplus capacity and energy, would effect increases in the total system costs of Southwest utilities. These increased costs would be reflected in

rate levels of those utilities. To the extent that higher BPA revenue levels result in higher retail rates of Southwest utilities, some reduction in the quantity of electricity demanded by all classes of customers could occur, along with some nominal decreases in employment in the Southwest's manufacturing and small business sectors which are affected by electricity costs.

It is not likely that increases in BPA revenue levels would result in significant increases in the operation of oil and gas generating units in California. Therefore, increased levels of sulfur oxide, nitrogen oxide, and particulate emissions in immediate locations of these units would not be expected. Given California's statewide commitment to displace its more expensive gas and oil generation to reduce its dependence on these fuels for electricity, as well the attendant advantages of displacing these resources with imports of out-of-state purchases, California utilities would be more likely to seek additional surplus power from other utilities in the Pacific Northwest or Pacific Southwest if they reduced purchases from BPA for pricing reasons.

(2) Effects on Low-Income Consumers

Income level, as well as a number of other variables including homeowner/renter status, location of residence, mix of energy sources utilized, retail rate structure, and family size affect the ability of low-income consumers to adjust to increases in electricity costs. For example, 33 percent of the poor, but only 8 percent of the nonpoor, reside in apartments. In many cases, the poor have no incentive to conserve because utility costs are included in rent and unit controlled thermostats may not be available (Grier, 1977, p. 17). In addition, capital intensive conservation measures are more difficult for most renters to implement than is the case for homeowners.

In 1979 those with incomes of less than \$5,000 (1979 dollars) spent 23 percent and 26 percent of that income on food and shelter, respectively. Those earning \$25,000 and more spent only 12 percent and 10 percent, respectively, of total gross income on food and shelter (Bureau of Labor Statistics, 1978, p. 387). The low-income consumers averaged expenditures of only \$3,838 per year for food and shelter compared with \$11,560 averaged by those with high incomes (1979 dollars).

The effects of the no action revenue alternative would be of greater immediate benefit to the poor than to other electric consumers. At the retail level, some increase in electricity prices would no doubt occur even under the no action alternative as a result of the effects of inflation on those portions of utility costs not associated with purchasing power from BPA. Under the base rate alternative (maintaining the rates in effect before December 20, 1979), electricity would be a relatively cheap commodity even if a utility's other costs increased at about the overall inflation rate. This would stimulate the use of electricity and encourage purchases of electricity consuming devices.

The proposed and direct financing revenue alternatives, in contrast, would increase the amount and proportion of a household's income paid for electricity. While high-income households may pay

more in absolute terms, the increase in the proportion of total income paid would be less in most cases than for low-income consumers. Although the magnitude of the proposed alternative would cause low-income households to conserve electricity, their limited financial resources inhibit capital investment in conservation. Furthermore, the uses to which the poor put electricity include a higher proportion of primary needs (cooking, lighting, refrigeration) than other uses (air conditioning, decorative lighting, etc.). Thus, their reductions in use often require changes in comfort or lifestyle.

The LRIC alternative could have a significant short-term impact on low-income households compared to the no action or proposed alternatives. Low-income consumers could be required to alter their lifestyles substantially. While the impacts of the LRIC alternative could affect the low-income, it could also worsen the problems of the near poor and those with moderate incomes. These consumers struggle to protect their limited incomes from the pressures of inflation. Imposition of LRIC based rates could erode their purchasing power and require lifestyle changes.

The proposed, direct financing and LRIC alternatives could pose serious problems for low-income elderly, who number approximately 150,000 in the region. In the mid-1970's, the impact of energy price inflation increased the portion of the elderly poor's budget spent on fuel and utilities by an average of nearly 10 percent in the Pacific Northwest (Federal Energy Administration, 1975, p. 2.44). Many live on fixed incomes that will not allow for flexibility to reduce their energy use or to shift home expenditures.

The consequences of the proposed and LRIC level alternatives would be particularly acute for the fixed income elderly. This segment of the population also tends to be in worse health than the young and may be more vulnerable to strains on mental and economic well-being. Moreover, the elderly poor often live alone, underutilize public services and, when they get ill, stay sick longer. Their health problems are aggravated by the cold (e.g., respiratory ailments, arthritis, accidental hypothermia), which increases the potential hazards of adapting to lower home temperatures (Design Alternatives, 1979, p. 6).

d. Effects on Business

Assessing the effects of an electricity price increase on the operations of business is complex and, because of the diverse characteristics of businesses, somewhat speculative. Generally, electricity serves as a minor cost input in comparison to such factors as costs of labor, materials, production process equipment, and transportation. Thus, an increase in electricity price generally is not a determining factor in the economic viability equation for businesses. Exceptions to this conclusion occur for those industries where electricity is a major input in production or for those businesses which operate near the margin and are unable to pass increased costs to their customers.

When the large group of energy conscious businesses is divided into subgroupings, the class of small businesses emerges as one which has been expressing growing concern with the continual raising of electricity rates. Small businesses are not a homogenous group and selected small

employers may be hurt more than others by rising energy costs. Arc welding, mills with energy intensive machinery, businesses with unusually high lighting, heating, and/or air conditioning needs (e.g., grocery stores/supermarkets) are particularly sensitive to electric rate increases. BPA sponsors several conservation programs which are available to assist entrepreneurs in increasing the efficiency of their electricity use.

In a telephone survey of selected small business organizations conducted in the fall of 1982, no single respondent identified energy costs as being the primary reason for loan default. These loan specialists, however, discussed management problems as being the major cause for bankruptcy. Entrepreneurs who fail are often those who lack good management practices and who make poor management decisions. Such problems of operation as cash flow, however, may be attributed in part to higher energy expenses. Improved management training is seen as the best means to improve the success rate among newer small businesses.

e. Effects on Energy Intensive Industry

Energy intensive industries are particularly sensitive to increases in the price of electricity. Industries for which electricity is a major factor in production include primary metals (aluminum, other nonferrous metals, and iron and steel), mining, chemicals, and pulp and paper. Such industries may respond to increased power costs through changes in production levels and/or changes in operation of plants, including relocation to areas with lower power rates. These actions would, in turn, have socioeconomic impacts on the region and potentially can affect the operation and recovery of costs of the Federal power system.

The aluminum industry is the most energy intensive industry in the region. The current national aluminum market is characterized by slow demand, low product price, excess inventories, and foreign competition. In the international market, the potential exists for a shift of aluminum smelter capacity in favor of foreign production. Any relative increase in U.S. power costs will further reduce the U.S. competitive position.

In the regional market, if the aluminum producers perceive that the Pacific Northwest has lost its historical comparative cost advantage, plant curtailments, shutdowns or other similar changes in operations can be expected. The 1983 average electric power cost per pound of aluminum produced in the region is projected to be the second highest among domestic producing regions (Tennessee Valley Authority, Ohio Valley, Northeast, Pacific Northwest, and Gulf Coast).

Because of confidentiality constraints, data were not available to analyze individual smelting plants. However, it is clear that there is significant variation in operating costs among Northwest plants. For the least efficient plants, the companies face decisions to improve plant efficiency, convert to "swing plant" operation, or permanently close down. In the long run, this may produce a positive effect if the industries improve efficiency and increase output for each increment of energy consumed. If plants were to close, however, there would be localized short run negative effects on employment and tax revenue.

Changes in either operation or level of operation by the aluminum industries can also effect the operation of the Federal power system. The level of impact corresponds to the change in DSI load. To the extent that DSI loads decrease, BPA could lose (1) reserves; (2) a market for nonfirm energy; and (3) stability of load (see Chapter IV.D.).

In January 1983, the Pacific Northwest aluminum industry was operating at about 61 percent of capacity (Direct Service Industries, Inc., February 1983). During 1981, nearly 600 employees were laid off (Direct Service Industries, Inc., 1982) and this trend is believed to have continued in 1982.

For smaller communities, which, in several cases have developed and grown with these industries over several decades, the greater their dependence on these plants, the greater would be the impact of a plant shutdown on the community's economy. Plants located in urbanized counties with diversified economies have a significant but less than critical impact on the county and local economy. Several of the direct-service plants, however, are sited in rural communities with populations of less than 50,000 where the facility often is the main industrial activity. The DSI customer in this less diversified economic setting may well be a critical component of employment, income, and tax support for services of the local area. In six counties in which DSI plants are sited, these plants directly and indirectly represent between 19 and 37 percent of the total county employment. Impacts approaching this level can bear significantly on the economic balance of local areas.

Using a simulation model, forecasts were made of the level of aluminum production as a function of factors relating to price for and cost of producing aluminum. The model, predicated on a much improved economy over that which currently exists, assumes a general increase in the demand for aluminum towards the end of 1983. This projected demand increase would be sufficient to override the effect of the proposed rate increase. The expected result would be an increase in regional production from 1982 levels and a corresponding increase in DSI loads. It is not known how this projected production increase would be allocated throughout the region. Production might increase in a limited number of plants, while curtailments continue in others.

The impacts on the physical environment of a DSI's decision to close include a reduction in air pollution loadings in any of the areas where plants are sited. Impacts on water quality, terrestrial environment, and health effects, would be reduced. After a period of nonoperation, the local environment might return to pre-plant status, although other industry might develop in the area in the meantime (see Section III.B.2.).

Industrial customers of retail utilities account for about 60 percent of historic industrial loads in the Pacific Northwest, with the remaining 40 percent consumed by the DSI's. The industrial customers of public utilities who serve all or a portion of their loads with BPA wholesale power could be affected by increases in wholesale power costs.

Output from the Supply Pricing Model for the five revenue level alternatives provided a basis for comparing projected composite public

agency retail industrial rates corresponding to each alternative. The model results suggest that, while increases in wholesale rate levels generally result in higher industrial rates at the retail level, the effects of wholesale rate increases may be diluted since BPA priority firm power constitutes only a portion of the total system costs of retail utilities. In addition, some utilities own and operate their own sources of power, such as low cost hydroelectric units, further enabling the utility to mitigate the magnitude of any increase in priority firm power costs. Finally, retail rate designs can affect the level of impact to industrial customers, depending on the manner in which the servicing utility allocates its costs among its customer groups and the extent to which it attempts to recover its costs from energy charges.

There may be some measures that industrial customers could take if their level of energy intensiveness or their current profit margins render them sensitive to increased electricity costs. There may be opportunity to avoid some capacity charges, depending on the retail utilities' rate structure, by switching loads to off-peak hours. In some cases, industries may be able to receive a portion of their energy requirement in the form of less-expensive nonfirm power. Other measures could include installing alternate fuel use capabilities such as oil or gas burners, or installing on-site electrical generation.

Where the effects of electricity costs cannot otherwise be mitigated, firms may cut back or shutdown their operations temporarily until product prices improve. Some firms, particularly those that are not based in the region because of indigeneous supplies of production resources and who may be affected by factors other than electricity (e.g., labor costs, proximity to markets), may find it economic to permanently shut down their regional production and shift their operations to other areas.

Shutdowns would result in the loss of jobs and incomes within immediate locations of affected plants. In the absence of development of new industries, permanent shutdowns would reduce local tax bases. The extent to which shutdowns would be felt by communities would depend on the local economy's dependence upon the industry. Local air quality, water quality, and the terrestrial environment could be expected to improve over time as a result of shutdowns.

f. Effects on Irrigated Agriculture

In the Pacific Northwest, one of the largest single energy consuming agricultural operations is irrigation. Furthermore, use of irrigation water is the most important factor affecting crop production. Since 1950, in the Pacific Northwest, there has been a pronounced increase in irrigation energy requirements. This increase is due to the invention of high lift pumps, labor saving equipment, new uses for irrigation sprinklers, inexpensive electric energy, and more profitable cropping patterns.

Table II-6 shows irrigated cropland in the Pacific Northwest in 1980. In 1980, there were approximately 7.6 million acres of irrigated cropland in the Pacific Northwest, approximately 53 percent of which (about 4 million acres) was sprinkler irrigated. The balance, about 3.6 million acres, was irrigated by gravity methods. Irrigated pasture contributed an additional estimated 1 million acres of irrigated land. The vast majority of irrigated pasture is irrigated by gravity methods. Irrigated pasture accounts for a small and extremely variable amount of total irrigation electricity loads and is not included in electricity projections discussed in this section.

(1) Responses to Revenue Level Alternatives

Projected impacts of the revenue level alternatives are described for the following categories: (1) total irrigated cropland acreage and sprinkler irrigated acreage; (2) water used for irrigation; (3) power requirements for cropland irrigation; (4) on-farm labor; and (5) the amount of generation capability available to serve alternative loads.

TABLE II-6
IRRIGATED LAND IN THE PACIFIC NORTHWEST, 1980

<u>Line No.</u>	<u>State</u>	A	B
		<u>Total</u> (1,000 acres)	<u>Sprinkler Irrigated</u> (1,000 acres)
1.	Idaho/Western Montana	4,105	1,917
2.	Oregon	1,716	852
3.	Washington	1,813	1,241
4.	Total	<u>7,634</u>	<u>4,010</u>

Source: Northwest Economic Associates, 1983

An increase in retail electricity prices would be expected to reduce the amount of irrigated cropland. Sprinkler irrigation, because of its greater power requirements, would be expected to be more price sensitive than flood irrigation. These expectations are consistent with the results obtained through use of linear programming model described in IV.C.2. These results are presented in Table II-7. Furthermore, as the share of sprinkler irrigation to total irrigation falls, on-farm labor requirements increase, thereby stimulating employment. This largely is because gravity irrigation is more labor-intensive than sprinkler irrigation. A relative shift away from energy-using sprinkler systems will lead to a decrease in regional energy use per acre; however, this will be offset to some extent because shifts to flood irrigation from more water-efficient sprinkler systems will increase regional irrigation water use per acre.

The analyses performed by BPA indicate that a change in irrigated acreage has two major effects on the hydroelectric system. First, a reduction in acreage leads to a reduction (offset to some degree by a

shift toward less water efficient gravity systems) in the quantity of water withdrawn from the river for irrigation purposes. This, in turn, means that the amount of river water available for power generation is increased. The converse is expected if the number of irrigated acres increases. Secondly, a reduction in irrigated acreage creates a drop in the amount of power used to run the irrigation systems thereby permitting use of generation facilities to serve other customers and reducing the need to develop additional facilities to meet load growth. Each effect is influenced by other factors such as a change in irrigation methods and systems or a change in cropping patterns.

Table II-7 shows the projected impacts of the revenue level alternatives on total irrigated cropland acres (gravity and sprinkler) and sprinkler irrigated acres. Increases in both total irrigation and sprinkler irrigation are projected under all revenue level alternatives relative to the 1980 base. The LRIC alternative, however, is projected to result in a slight decrease in the share of land irrigated by sprinkler methods. The other alternatives lead to small increases in the share of sprinkler irrigated land.

The LRIC alternative would, over the next 5-7 years, result in negligible net new sprinkler irrigation. The bulk of net new irrigation would be on gravity systems, and would be most likely to occur on land receiving water from the Bureau of Reclamation.

By 1990, the cumulative effect of BPA's historic and proposed rate increases is projected to result in a reduction of 42,000 sprinkler irrigated acres. This reduction in sprinkler irrigated acreage is partially offset by an increase of 5,000 gravity irrigated acres. The net reduction is 37,000 irrigated acres. The effect of the rate increases is the trade of energy intensive irrigation for water intensive irrigation. Water intensive irrigation has a negative effect on the overall generation capability of the river system.

TABLE II-7
IMPACT OF REVENUE LEVEL ALTERNATIVES ON
IRRIGATED CROPLAND ACREAGE
IN 1990 AND 2000

		A	B	C
Line No.	Revenue Level Alternatives	Total Irrigated Cropland (1000 acres)	Sprinkler Irrigated Cropland (1000 acres)	Percent Sprinkler Irrigated Cropland
Year 1980				
1.	Base Rate	7,634	4,010	52.5
Year 1990				
2.	Base Rate	7,929	4,266	53.8
3.	No Action	7,897	4,221	53.5
4.	Proposal	7,892	4,204	53.3
5.	LRIC	7,826	4,022	51.4
Year 2000				
6.	Base Rate	8,223	4,521	55.0
7.	No Action	8,216	4,461	54.3
8.	Proposal	8,216	4,461	54.3
9.	LRIC	8,204	4,259	51.9

Source: Northwest Economic Associates, 1983

Table II-8 shows, for 1990 and 2000, projected water use, electricity use, and farm labor under the revenue level alternatives. This table shows the following general relationships. First, water use increases as electricity prices increase. This effect is largely because relatively less land is irrigated by energy-intensive, but water-saving, sprinkler methods. Differences in water use under the revenue level alternatives are less than might be expected. This is because higher electricity prices encourage adoption of improved management techniques that reduce per acre water use of sprinkler systems. Secondly, electricity use decreases as electricity price increases because relatively less cropland uses energy-intensive sprinkler systems and existing sprinkler systems adopt (or convert to) more efficient sprinkler systems and management techniques. Finally, more on-farm labor is required as electricity price increases lead to use of relatively more labor-intensive methods such as flood irrigation.

Table II-8 further shows that projected differences between the revenue level alternatives tend to diminish over time. For example, the cumulative electricity price effect (difference between the Base

Rate and Proposal) is projected to be 410 GWh in 1990 but only 125 GWh in 2000. The cumulative water use effect decreases from 496,000 acre-feet in 1990 to 166,000 acre-feet in 2000. Farm labor cumulative effects also diminish over time. There are two primary reasons for this result. First, more farmers will be able to adopt improved irrigation technology and practices over the longer term. Second, the real price differences between the alternatives diminish over time.

TABLE II-8
IMPACT OF REVENUE LEVEL ALTERNATIVES ON
IRRIGATION WATER USE, ELECTRICITY, AND FARM LABOR
IN 1990 and 2000

Line No.	Revenue Level Alternatives	Water Use (1,000 acre-feet/yr)	Electricity Use (GWh/yr.)	Farm Labor a/ (1,000,000 hours/yr.)
Year 1980				
1.	Base Rate	25,899	4,430	334
Year 1990				
2.	Base Rate	25,168	4,452	362
3.	No Action	25,554	4,103	364
4.	Proposal	25,664	4,042	365
5.	LRIC	26,414	3,552	368
Year 2000				
6.	Base Rate	24,437	4,473	390
7.	No Action	24,603	4,348	391
8.	Proposal	24,603	4,348	391
9.	LRIC	25,227	3,980	394

a/ Excludes food processing labor.

Source: Northwest Economic Associates, 1983.

Table II-9 shows the impact of differences in projected water and electricity use by irrigators under the revenue level alternatives on power generation capability available to serve nonirrigation loads.

The impact on generation capability available to serve alternative loads is, for this analysis, a function of (1) power needed for irrigation; and (2) surface water withdrawals.

As shown in line 1 of Table II-9, the No Action, Proposal, and LRIC alternatives use less electricity for irrigation in 1990

TABLE II-9
IMPACT OF REVENUE LEVEL ALTERNATIVES ON AMOUNT OF
GENERATION CAPABILITY AVAILABLE TO SERVE
NONIRRIGATION LOADS
(GWh/yr)

<u>Line Number</u>	<u>Condition</u>	<u>A Base Rate</u>	<u>B No Action</u>	<u>C Proposal</u>	<u>D LRIC</u>
Year 1990					
1.	Sprinkler Irrigation Power Requirement	4,452	4,103	4,042	3,552
2.	Reduction in Power Requirement from Base Rate	0	349	410	900
3.	Decrease in Generation Capability Due to More Water Withdrawal	0	193	248	623
4.	Net Increase in Generation Capability Available to Serve Other Load (Line 2 Minus Line 3)	0	156	162	277
Year 2000					
5.	Sprinkler Irrigation, Power Requirement	4,473	4,348	4,348	3,980
6.	Reduction in Power Requirement From Base Rate	0	125	125	493
7.	Decrease in Generation Capability Due to More Water Withdrawal	0	83	83	395
8.	Increase in Generation Capability to Serve Other Load (Line 6 Minus Line 7)	0	42	42	98

than does the Base Rate alternative. This results in, respectively, 349, 410, and 900 additional gigawatthours of power available to serve other loads in 1990. Somewhat offsetting these savings, however, is foregone generation capability due to increased water withdrawals (lines 3 and 7). The net result, however, shows a direct relationship between revenue level and generation capability available for nonirrigation service (lines 4 and 8).

However, that the largest increases in available generation capability are forecast to occur during the 1980's when BPA forecasts surplus generation capacity. In 2000, the potential increase in

generation capability under the LRIC alternative (98 GWh) is about 7 percent as much as the capacity of a mid-sized (150 MW) combustion turbine generating facility.

Total power requirements in both 1990 and 2000 are less than the 1980 base for all but Base Rate alternative. Water use is lower than the 1980 base in all cases except the 1990 LRIC. This results from a relatively large share of net irrigation development using water-intensive gravity methods in the short run to counteract the relatively high LRIC rate level.

Generally, energy prices are projected to hasten adoption of improved irrigation management and technology. A decrease in power requirements and water use is projected, compared to 1980, despite increases in both gravity and sprinkler irrigation.

In summary, this analysis projects that net additions of total irrigated land and sprinkler irrigated land will occur under all alternatives. An inverse relationship is projected between both gravity and sprinkler irrigation and revenue level. Also, the share of sprinkler irrigation to total irrigation declines as the revenue level increases. Relative declines in labor-saving sprinkler systems leads to projected increases in on-farm labor.

(2) Long-Term Socioeconomic Ramifications

The regional socioeconomic impacts of increased electricity price for irrigation are a function of the number of farms, acreage, crop value, and location of irrigated acreage that either reverts to dryland farming, or is taken out of production. These factors further impact the viability of agricultural processing firms that frequently are dependent on harvests from nearby producers.

Net growth in irrigated acreage is projected to occur for all alternatives relative to the 1980 base. However, some land that currently is irrigated will revert to dryland farming. Other irrigated land will revert to desert. In some cases conversion to irrigation may be deferred, or not occur at all. Each of these impacts is most pronounced under the LRIC alternative. Relatively small acreage reductions are projected under the No Action and Proposal Alternatives.

Though the amount of regional acreage moving out of irrigation, or production entirely, is small, some areas may be more adversely affected than others. Particularly vulnerable areas are those with sandy soils, low rainfall, and high pump lifts from water source to point of application. Areas that generally fit this description are the Columbia Basin in Washington, the Columbia Bench in Oregon, and selected locations in Southern Idaho. Current information is inadequate to determine which communities have a large proportion of marginal farms and, therefore, which communities may experience a disproportionate share of social and economic impacts.

Socioeconomic impacts also may be influenced by how wholesale power rate increases affect the operating costs and revenues of

participation in acreage control programs (Kendall, 1983). The improving U.S. economy is expected to strengthen domestic consumer demand. High interest rates and a strong dollar, however, suggest that the export market will not improve as quickly as the domestic market.

The near-term situation, then, is an agricultural sector that must experience significant crop price increases to prevent further cash-flow deterioration. Farmers would also benefit from improvements in the price of production inputs. Certainly, price increases for any significant production input (such as electricity that contributes 5-10 percent to a typical irrigator's total costs) will, with no change in other factors, adversely impact agriculture.

g. Effects on the Physical Environment

The primary physical environmental effects of an increase in BPA's revenue level are those that are avoided because of the difference in the amount of generation required to serve load and those that result from switching to other sources of energy. As noted earlier, the proposed and LRIC revenue level alternatives would require less generation by the year 2000 (1,607 MW and 5,129 MW, respectively) than would the no action alternative. Conversely, the cumulative Base Rate alternative would require 2,391 MW of additional resources compared with the no action alternative.

The Least Cost Resource Mix linear programming model, used by BPA to forecast future resource composition, considers coal and nuclear generation individually as potential resources. However, the relative cost effectiveness of these two resources has not been definitively established. Some of the key considerations for evaluating these two technologies for potential additional generation are still being examined. These considerations include relative costs of coal and nuclear resources, their environmental impacts and other issues. For this reason, coal and nuclear resources identified by the resource mix model are combined and characterized as "large thermal" resources for the purposes of this study.

Also, the Regional Council has recently proposed to add combustion turbines to the region's resource mix to meet future energy needs. BPA has not yet confirmed or refuted the cost effectiveness of building new combustion turbines to meet energy needs. While this resource does not appear in the resource mixes examined here, it should be recognized as a possible substitute for some of the large baseload thermal additions from the resource mix model.

Using the resource mix model, distinct resource configurations can be identified for each revenue level alternative (see Chapter IV.B.3.). Once identified, the potential environmental effects can be evaluated. The environmental effects (Chapter IV) of small hydroelectric, conservation, and cogeneration vary depending on application and siting. The environmental impacts of these resource technologies are relatively minor when compared to large thermal power generation (Chapter IV.H. 4 and 5). Therefore, major environmental impacts are measured in terms of large thermal power generation.

public agency utilities with a large number of irrigation customers. Most of these utilities do not have a diversified customer base, and thus may experience difficulty in maintaining revenue stability through retail pricing or marketing strategies. Irrigated agriculture accounts for more than 20 percent of total sales for 18 of BPA's customer utilities; for seven of these utilities, sales to irrigators comprise more than 50 percent of total sales. Many of these utilities serve areas where irrigation water must be lifted a long way before it is applied to crops. In these areas, electricity cost as a percentage of variable agricultural production cost is relatively large. These utilities may experience greater electricity conservation and more farm closures than other utilities, yet they are less able to recover lost revenue than are utilities with a more diversified customer base.

In reviewing testimony and comments received during the 1982 rate process as a part of the scoping process for this EIS, it became apparent that a major negative impact of rate increases is due to financial constraints that prevent many irrigators from making short-term technical changes to their equipment. Earlier irrigation investment and production decisions have been based in part on electricity price advantages considerably greater than exist today. Agricultural producers have historically operated at higher debt-to-asset ratios than most other domestic production sectors. Therefore, they are particularly ill equipped to make short-term and expensive investments in power conserving equipment.

A review of BPA's conservation program for irrigators is in Section IV.J.3.c. An irrigation rate alternative and rate design features that could mitigate impacts on irrigators are discussed in Section IV.I.

(3) Near-Term Socioeconomic Ramifications

Projected impacts of increased electricity prices for irrigation are relatively favorable by the years 1990 and 2000. Though the higher priced revenue level alternatives show cropland acreage reductions compared to the Base Rate, all alternatives show net growth in the agricultural sector compared to the 1980 base. Near-term impacts to irrigated agriculture are of some concern.

Farmers are in a weak cash-flow situation resulting from declining real net farm income over the last 3 years. Farm financial health is projected by most analysts to improve during the next 2 years, but not dramatically. Real net farm income in 1980 and 1981 "was the lowest of the past generation, and total income for the 2 years combined was not much higher than 1979 income alone" (Burke, 1982). 1982 was even harder on farmers than the previous 2 years. A U.S. Department of Agriculture indicator of net farm income showed a decline of nearly 9 percent in 1982 (USDA, 1983).

Pacific Northwest farm conditions generally parallel national trends though not always on a crop-by-crop basis. Recent indicators show signs of improvement. Farm production input costs (feed, seed, fertilizer, etc.) are still rising, but at a slower rate than in recent years. Crop prices generally are projected to increase due to both demand and supply factors. Harvests in 1983 are expected to be about 20 percent smaller than in 1982 due in part to unusually low rainfall in many areas and heavy

Table II-10 indicates that by the year 2000, the increases in rates under the proposed, direct financing and LRIC alternatives relative to the no action alternative dampen demand for electricity. This would avoid the need for and consequent effects to the physical environment of 1131 MW of large thermal capacity under all three scenarios. This would also avoid the environmental impacts associated with the mining, processing, and generation of that amount of large thermal power.

By the year 2000, the base rate alternative would increase the demand for electricity sufficiently to require construction and operation of generation facilities in addition to those already under construction in the region. The large thermal portion of this additional generation, with consequent effect on the environment, would exceed that required under the no action alternative by 2,174 MW of nameplate capacity.

Table II-11 summarizes the major environmental effects avoided or incurred annually, relative to those which would be expected under the no action alternative, by these revenue alternatives, based on the impacts of additional or avoided large thermal generation. Due to the uncertainty regarding the relative advantages of coal or nuclear generation, the physical impacts of large thermal were estimated using an assumed split of 50 percent coal and 50 percent nuclear generation. Column A shows the estimated additional impacts of the 2,391 installed MW of large thermal capacity forecast for FY 2000 under the base rate alternative. The proposed, direct financing and LRIC alternatives were each projected to result in 1,131 fewer installed MW of large thermal capacity than the no action alternative. The corresponding avoided physical impacts associated with either of these alternatives are shown in Column B. The proposed, direct financing and LRIC alternatives, while projected to result in the same amounts of large thermal generation capacity in FY 2000, differ greatly in the amounts of other resources required (See Table II-10). (Physical impacts associated with conservation, cogeneration, and small hydro were either not quantifiable, not applicable or negligible.)

The environmental effects of nuclear and coal generation are associated with three distinct stages occurring at different sites: mining, processing (various steps necessary to prepare mined coal or uranium for fuel use at generating sites), and power production. All the stages have land use, solid waste, water, and air quality impacts. For nuclear operations, these three stages generally occur at different sites, with mining and processing of fuel taking place outside of the region. Since the processing of coal fuel is generally done at the mine site, the physical impacts of processing coal fuel, as shown in Table II-11, are included in the mining stage for the coal portion of impacts.

The environmental effects avoided as a result of the lower need for electric generation facilities under the proposed, direct financing, and LRIC alternatives are offset by the physical environmental effects resulting from induced increases in the use of alternative energy sources. BPA's Energy Simulation Model assumes that the lower generation requirements under the proposed and LRIC alternatives will be compensated by increased use of natural gas, oil, and conservation based on appropriate elasticities and cross-elasticities among fuel types. In fact, the mix of alternative energy sources is far more complex and includes a variety of renewable resources as

TABLE II-10
VARIATION BY THE YEAR 2000 IN RESOURCE REQUIREMENTS AND
RESOURCE MIX IN RESPONSE TO
REVENUE LEVEL ALTERNATIVES a/

Line No.	Revenue Alternative	A Generation Requirement Relative to No Action Alternative (MW of capacity)	B Mix of Avoided or Additional Resources (MW of capacity)
1.	Base Rate	+ 2,391	conservation = 17 large thermal = 2,174 geothermal = 200
2.	No Action	(0)	(0)
3.	Proposal	- 1,607	conservation = - 49 large thermal = - 1,131 cogeneration = - 11 small hydro = -416
4.	Direct Financing	- 2,662	conservation = - 122 large thermal = - 1,131 cogeneration = - 138 small hydro = - 1,271
5.	LRIC	- 5,129	conservation = - 1,034 large thermal = - 1,131 cogeneration = - 393 small hydro = - 2,571

a/ These resource requirement data reflect the differences in capacity compared to the "No Action" alternative, as estimated by the Least Cost Resource Mix Model.

TABLE II-11
ENVIRONMENTAL EFFECTS OF GENERATION AVOIDED (OR ADDED) a/
ANNUALLY BY THE YEAR 2000 BY REVENUE LEVEL ALTERNATIVE

Line No.	A Base Rate (Increase)	B Proposal/Direct Financing/LRIC (Decrease)
<u>Mine Site</u>		
1. Land Use, Permanent (acres) b/	243.5	126.7
2. Overburden Removed (tons)	3,319,878.9	1,727,131.1
3. Process Water Used (acre/ft)	158.0	82.2
4. Solid Waste (tons) c/	577,903.6	300,648.1
Air Pollutants (tons)		
5. Particulates	1,808.4	940.8
6. SO ₂	76.4	39.8
7. NO _x	128.8	67.0
8. Hydrocarbons	52.3	27.2
9. CO	87.3	45.4
10. Other c/	17.7	9.2
Water Pollutants (tons) c/		
11. Dissolved Solids	5,984.9	3,113.6
12. Suspended Solids	68.4	35.6
13. Other	1,320.9	687.2
<u>Process Sites</u>		
14. Land Use, Permanent (acres) b/	2.4	1.2
15. Process Water Used (acre/ft)	33,396.4	17,374.1
16. Solid Waste (tons) c/	70.8	36.8
Air Pollutants (tons)		
17. Particulates c/	1,221.9	635.7
18. SO ₂	4,703.4	2,446.9
19. NO _x	1,238.4	644.3
20. Hydrocarbons	12.7	6.6
21. CO	31.1	16.2
22. Water Pollutants (tons) c/	116.7	60.7
<u>Generating Site</u>		
23. Land Use, Permanent (acres) b/	480.5	250.0
24. Process Water Used (acre/ft)	37,976.5	19,756.9
25. Solid Waste (tons)	922,307.2	479,820.4
Air Pollutants (tons)		
26. Particulates c/	12,737.5	6,626.5
27. SO ₂	14,234.2	7,405.2
28. NO _x	20,179.4	10,498.1
29. Hydrocarbons	751.2	390.8
30. CO	2,288.0	1,190.3
31. CO ₂	7,312,249.0	3,804,118.5
32. Other c/	9.5	4.9

TABLE II-11, Cont.

Line		A	B
<u>No.</u>		<u>Base Rate</u> (Increase)	<u>Proposal/Direct</u> <u>Financing/LRIC</u> (Decrease)
	Water Pollutants (tons)		
33.	Dissolved Solids	20,650.1	10,743.0
34.	Suspended Solids	7.8	4.1
35.	BOD	33.0	17.2
36.	COD	3,236.2	1,683.6
37.	Nitrates	44.1	23.0
38.	Other <u>c/</u>	14.7	7.6

a/ All comparisons are made relative to the no action alternative.

b/ This represents total permanent disturbance and is not annualized.

c/ Radioactive materials included.

well. The unknown nature of future substitution of alternative energy sources and the complexity of the actual mix makes quantification of the resulting environmental effects very speculative. The potential effects of alternative resources will be briefly described, but no quantification of the net environmental effects of the revenue alternatives has been attempted.

Combustion of oil and natural gas causes atmospheric emissions of carbon monoxide, sulfur oxides, nitrogen oxides, carbon dioxide, hydrocarbons, particulate matter, water, and other materials. Additional impacts include increased solid waste disposal and increased impacts from extracting, refining, processing, and transporting the fuel. This increased direct fuel usage, from the proposed, direct financing, or LRIC alternatives, is most significant in populated areas where air quality problems exist such as Seattle, Everett, Tacoma, and Vancouver in Washington, and Portland and Eugene in Oregon. Of these cities, only Everett does not currently violate one or more ambient air quality standards.

The environmental effects associated with the major renewable resources are summarized in Table II-12. Of these, direct combustion of wood for home heating has the most substantial environmental consequences. The Oregon Department of Energy finds that "burning wood for home heating is the most rapidly growing source of air pollution in Oregon and the Pacific Northwest" (Hazen, 1980). For example, in Medford, Oregon, emissions from wood used for home heating are the source of two-thirds of the smaller, more harmful smoke particulates. In the Portland Metro Area, particulate emissions from home wood burning have surpassed industrial point sources on the Pollution Index. (See Chapter III.B.1.e.(1) for further discussion.)

Generally, the inputs to conservation involve mining raw material; manufacturing construction materials such as metals, glass and insulation; fabricating the finished products; transporting to the point of use; and installing. These activities affect levels of air and water

pollutants and the potential risk for accidents. Indoor air quality is a concern associated with weatherization of homes, and is the subject of a separate BPA Environmental document (BPA, 19821). Many conservation activities are relatively labor intensive and therefore have beneficial socioeconomic effects.

Environmental effects of cogeneration are dependent on the specific site, types of fuel used, and design and operation of the facility. In general, cogeneration tends to increase environmental effects in the immediate locale of the facility. The increased fuel efficiency of cogeneration from simultaneous steam and electricity production results, however, in lower net levels of pollution on a regionwide scale when compared with pollution levels from a separate electric generating plant.

Environmental impacts to air quality at the local level include additional particulate air emissions, carbon monoxide, and other substances depending on the facility. There may be a need, in some cases, to divert water otherwise available for domestic supply or recreation to handle waste from cogeneration processes. In addition, solid wastes from some cogeneration processes may be classified as "hazardous waste."

TABLE II-12
ENVIRONMENTAL EFFECTS OF MAJOR
RENEWABLE RESOURCE TECHNOLOGIES

<u>Line No.</u>	<u>Technology</u>	<u>Environmental Effects a/</u>
1.	Passive Solar	indoor air quality, fire control
2.	Active Solar	structural safety, occupational hazard (installation) disposal of waste collector fluid
3.	Wind	structural safety in high winds
4.	Wood Combustion	hydrocarbon, carbon monoxide, and particulate emissions, fire hazard
5.	Geothermal	noise, brine, and effluent disposal
6.	Photovoltaics	occupational hazard (installation)
7.	Biomass Conversion	land use, soil depletion, erosion, air pollution

a/ Sources: Bossong, K., 1981, "Hazards of Solar Energy," The Energy Consumer, U.S. Department of Energy, Washington, D.C., pp. 26-27, January; Hayes, D., 1981 "Environmental Benefits of A Solar World," The Energy Consumer, U.S. Department of Energy, Washington, D.C., pp. 27-28, January; and U.S. Department of Energy, U.S. Department of State, 1981c, New and Renewable Energy in the United States of America, DOE/S-0006 Washington, D.C., June.

Both electricity and the direct use fossil fuel for space heating produce air pollutants per unit of heat. However, the location of the pollution source and the ability to regulate the level of pollutants are important factors in assessing their impacts on the human environment. Electric generating plants, by the restrictions placed on their operation,

design, and siting, are required to meet air quality standards and "prevention of significant deterioration" regulations. Most are located away from large population centers. In this respect, air quality impacts on humans of electric generating plants may be less than the impacts on humans of direct application of fossil fuels or numerous small combustion plants. The latter activities are not as amenable to regulation, or use of technological means to limit emissions, as they generally exist in populated areas with air quality problems (Charles River Assoc., 1978, pp. 175-179; Gordian Assoc., 1972 and 1974).

In terms of the agricultural sector, the reductions in water use for irrigation under the proposed and LRIC alternatives in irrigation discussed previously in section II.B.3.f. could result in appreciable environmental benefits. These environmental benefits include lower levels of water withdrawals, reduced chemical contamination due to irrigation runoff, and reduced stream siltation. These effects could be significant for particular aquatic environments.

Land which is not irrigated or is removed from irrigation due to high electricity prices, could be unfarmed or be limited to dry land agricultural production or grazing. The Public Health Service has expressed concern that the expansion of irrigation projects has usually been accompanied by proportionate increases in aquatic habitats favorable for the production of undesirable insects. Mosquitoes are the most important of these insects. There is concern that irrigated land, when not farmed, could become a breeding ground for mosquitoes. However, most areas projected to be removed from irrigation currently are sprinkler irrigated and in high lift zones. Consequently, there would be no untended channels or ditches that might become breeding grounds.

BPA does not foresee any significant changes due to revenue level alternatives in operation of the hydro system. By the year 2000, approximately 1.3 million fewer acre-feet of water are projected to be required for irrigation under the proposed alternative than would be required under the base rate alternative. Approximately 54 percent of this 1.3 million acre feet of water would return to the Columbia and its tributaries through runoff and underground aquifers (Whittlesey, 1982). The remainder would be lost through evaporation and containment in harvested crops. The amount of this loss would be less than one percent of the average annual flow of the Columbia River as measured at The Dalles, Oregon. Additional reduction in water loss under the LRIC alternative also would be negligible relative to total river flows. Furthermore, water withdrawals for irrigation occur primarily during the periods of greatest river flows. For these reasons, the potential effect of the various rate alternatives on the operation of the Federal Columbia River Power System and the use of the Columbia River and its tributaries would not be expected to differ significantly.

C. Rate Design Alternatives and Their Impacts

BPA is one of a class of wholesalers of electric energy which does not directly serve the general consuming public, except for a few very large industrial consumers. Such regional wholesalers are quite common outside the United States. Both England and France are served by nationally owned

wholesale power systems. The Canadian province of Ontario is served by a similar system. All these regional wholesalers supply part or all of the power requirements of local distributors.

The pricing policy of the regional wholesaler is generally influenced much more strongly by its budgetary requirement, and less so by the nature of end-users' demands, than are the price policies of local distributors who are in immediate contact with end users. Within regulatory or legal constraints, prices are set to recover an annual revenue requirement; but the regional wholesaler cannot influence the amount of service demanded except to the extent that the level of the wholesale rate structure limits use. As long as the law requires service to all who want service at the administered and legally approved price, the wholesaler must estimate the demand for power and then provide in advance the capacity to serve it. The wholesaler must then set the price at a level so that it can be reasonably assured of enough revenue to recover all the costs which have been obligated.

This is not to say that wholesale prices cannot influence the consumption of electric service, but they can do so only to the extent they influence the rate policies of retail distributors. The wholesale prices are a cost component which must be recovered by retail distributors and, therefore, are reflected in the retail utility rates. However, there are gaps in time and in consumer recognition of cost changes due to wholesale rate adjustments which greatly diminish the sales impact of wholesale price changes as compared with changes in the retail rates. Furthermore, the costs of local subtransmission and distribution systems may weigh more in the final retail pricing structure than the costs of bulk energy supply (BPA, 1979b, p. IV-4). In consequence, opportunities to influence energy use are much greater for ratemaking policy at the retail than at the wholesale level.

A discussion of the various revenue levels which BPA could seek to recover through its wholesale power rates was presented in Section II.B.1. In general, the higher the amount of revenue BPA seeks to recover, the higher will be the rates required. The decision regarding the amount of revenue to be recovered is the most significant factor in determining the level at which BPA will establish its wholesale power rates for various services. Revenue over or undercollection is possible in a given year or series of years. Excess revenue would be used to either offset deferred amortization or, in the absence of a deferral, make advance amortization payments. Revenue undercollection would produce a need to increase the amount of revenue collected from future ratepayers. Streamflow, temperature, power purchases, economic conditions and/or other factors that may affect a given year's power supply/demand situation can affect the balance between costs and revenue recovery.

The revenue level required by BPA will affect the level of wholesale rates and will, in turn, be reflected in the level of retail rates. Assuming the demand for electricity by consumers is sensitive to retail price, the need to construct and operate power generation facilities could be affected by changes in wholesale power rates. Thus, the environmental effects of constructing and operating power facilities could be affected by changes in wholesale power rates. The proposed and alternative revenue requirements are translated into the physical environmental impacts associated with the generation of electricity in Section II.B.3.

A rate design is a structure of prices for services rendered to many types of uses by several differentiated classes of users. The price of any good or service functions as a constraint upon its use. There is, accordingly, no such thing as a popular pricing scheme. From the point of view of the user, any decrease in price is good and any increase bad. From the point of view of the producer, the goal is to achieve a perfect correlation between cost and revenue. From the viewpoint of public interest, the best price is one which fosters most efficient use of the physical and social environments.

Since rate design impacts the distribution of the revenue burden across customers, it may affect the demand for and the use of electricity. While BPA has an indication of what the level of its wholesale rates will mean in terms of average retail cost to the end use consumer, that is not the case for the design of the wholesale rates. Rate design reflects specific criteria. If a wholesale rate design criterion is repeated at the retail level, then the wholesale design will have a direct impact on the end use consumer. However, the design function at the retail level is the responsibility of the retail utility. Therefore, reliable measurement of a direct impact of wholesale rate design on the end use consumer is not possible without knowledge of how it will be reflected in the rate designs of each retail utility. BPA can, however, analyze its wholesale rate designs from the perspective of how the design alters the level of costs to be recovered from its wholesale customer classes. While the rate level, as dictated by the revenue requirement, can be translated into physical and socioeconomic environmental impacts, the principal impacts of rate design are the socioeconomic impacts associated with shifting costs between BPA's customer classes. Rate design can also influence the price signal sent to customers on the social cost of providing an extra unit of electricity, and thus allow consumption decisions that yield an efficient allocation of resources.

The basic rate design objectives BPA pursues in designing its wholesale power rates include the following: (1) ensuring adequate revenue to meet its repayment obligation; (2) distributing the revenue requirement in an equitable manner among recipients of the service according to costs incurred and benefits received, and (3) designing rates to encourage efficient use of resources, including the Federal Columbia River Power System (FCRPS). Consideration is also given to rate continuity, ease of administration, revenue stability, and ease of understanding.

Table II-13 presents a summary of BPA's major rate design elements. The proposed revenue level (see also Section II.B.) specifies the total costs which have to be recovered from BPA's customers. The cost incurrence is identified by service class and then is allocated to customer classes. Rate design adjustments are made and the rates are developed to recover allocated costs. Table II-13 lists the design elements, the rate schedules to which they apply, and a description of the element. The table also identifies the objective for which the element was designed (insure adequate revenue level, revenue stability, or efficient operation of the Federal system).

TABLE II-13
RATE DEVELOPMENT SUMMARY

Design Elements	COSA	Rate Schedule Impact											Design Description	Design Objective		
		PF	IP	IH	CF	CE	NR	SP	SE	NF	EB	RP		Revenue Level	Stability	Operation of System
<u>Proposed</u>																
1. Functionalization	X												1. Assigns costs to system functions of generation and transmission.	X		
2. Classification	X												2. Divides functionalized costs between capacity and energy.	X		X
3. Seasonal Differentiation	X												3. A higher rate charge for peak usage months of the year.			X
4. Allocation	X												4. Assigns functionalized, classified and seasonally differentiated costs to customer classes.	X		
5. Excess Revenue Adjustment		X	X	X	X	X	X						5. Credits revenues in excess of allocated costs.	X		
6. Revenue Deficiency Adjustment		X			X	X							6. Allocates revenue deficiencies caused by fixed contract rates which cannot be adjusted to cover costs.	X		
7. Value of Reserves Adjustment		X	X	X	X	X	X	X	X	X			7. Allocates revenue deficiencies caused by crediting DSI's for restriction rights.	X		
8. Low Density Discount		X											8. Applies discount and allocates resulting revenue deficiency.	X		
9. Surplus Firm Power Adjustment		X	X	X	X	X	X	X	X				9. Allocation of revenue deficiency.	X	X	
10. Equalization of Demand Adjustment		X			X	X	X	X	X				10. Demand charges are equalized under provision of Regional Act.		X	
11. Hanna Adjustment		X	X		X	X	X	X	X				11. Allocates revenue deficiency from Hanna rate relief to all other customers.	X		
12. Modified Billing Determinants		X					X						12. Modification to compensate BPA for costs incurred in being ready to serve computed requirements customers.		X	
13. Customer Charge			X										13. A charge based on operating demand to share risk of DSI curtailment.		X	
14. Exchange Adjustment Clause		X	X		X		X	X					14. Automatically adjusts for differences between forecast and actual average cost of exchange resources.		X	
15. Supply System Adj. Clause		X			X								15. Automatically adjusts for changes in total cost of Supply System Plants 1, 2, and 3.		X	
16. Value of Reserves Credit			X	X									16. Partially compensates DSI's for BPA's restriction rights.			X
17. Sustained Peaking Surcharge					X								17. Additional charge to encourage 9-hour limit for taking capacity.			X
18. Diurnal Differentiation		X	X	X			X	X			X		18. A higher rate charge during peak usage hours of the day.			X
<u>Alternatives</u>																
19. Low Water Surcharge		X			X	X							19. Additional charge to cover cost increases due to poor water conditions.			X
20. Transformation charge		X					X						20. Charge for deliveries at lower voltage	X		
21. Deferral Adjustment Charge		X	X	X	X	X	X	X					21. Adjust for large revenue underruns or cost overruns during rate period.		X	

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The remainder of this section first presents a brief summary of each of the proposed rate design elements and a description of the expected environmental impacts. An explanation of the analyses undertaken to determine the environmental effects of each rate design element and related alternatives is contained in Section IV.I. Secondly, the expected environmental impacts of the proposed rate schedules are analyzed. The existing and proposed rate schedules are contained in Appendices A and B. The third part discusses the major rate alternatives.

1. Impact of Rate Design Elements

Changes in rate design elements affect wholesale power rates by increasing or decreasing the costs to be recovered by an overall rate to a customer group. There are a number of ways a customer/consumer can respond to the increase in wholesale power rates: (1) alternative sources of purchase power can be sought (switch power suppliers); (2) alternative sources of generation can be sought (fuel switching, cogeneration, conservation); (3) consumption can be reduced (turn down heat, lay off employees, reduce acres irrigated, reduce industrial output); and (4) power costs can be passed through to other consumers (higher retail rates, higher product prices). The overall effect is a decrease in the demand for power.

Conversely, there are a number of ways a customer/consumer can respond to the decrease in wholesale power rates: (1) the amount of power purchased from BPA may be increased; (2) alternative sources of generation will not be sought (less conservation, fuel switching, and cogeneration); (3) consumption can be increased (residential use increased, increased irrigated acreage, increased industrial output, higher employment levels); and (4) power cost savings can be passed through to other consumers (lower retail rates, lower product prices). The overall effect is an increase in the demand for power.

The environmental impacts associated with these customer/consumers reactions can be physical and/or socioeconomic. Physical impacts occur when there are changes, either negative or positive, on the quality of air, water, or land. For example, if a consumer decreases his consumption of electricity by burning wood for heat, there would be a negative change in air quality.

Socioeconomic impacts occur when there are changes, negative or positive, in the human environment. If the consumer reaction to higher power rates is to dismiss employees, there will be a loss of income in a community. One consequence of this loss is a reduction of the tax base supporting schools, roads, and other essential services. All other businesses in the community will be impacted. People may begin to move in search of other employment, disrupting community cohesion. Property values may fall. Attitude and value systems may change. Political bases may shift.

BPA's reaction to the customer/consumer response also has environmental implications. The response to higher rates is a decrease in the demand for power. In the long term this means that BPA will need fewer new generation resources constructed and operated. Therefore, the attendant adverse physical environmental impacts on land, air, and water quality will be

avoided. Also, in the long term, because the costs associated with the new generation resources will be avoided, the costs to be recovered from future ratepayers will be lower, implying positive future socioeconomic impacts.

The customer/consumer response to lower rates is an increase in the demand for power. In the long term this means that BPA will need additional generation resources constructed and operated, with attendant adverse physical environmental impacts on land, air, and water quality. Also, in the long term, this will increase the costs to be recovered from future ratepayers, implying negative future socioeconomic impacts.

a. Functionalization

The COSA step of functionalization has the objective of the assignment of costs to the power system functions of generation, transmission, and metering and billing. The proposed methodology results in \$2.3 billion being functionalized to generation and \$0.5 billion to transmission for OY 1985 (year ending June 30, 1985). All metering and billing costs have been functionalized to transmission. Alternative methods of functionalizing certain costs, such as conservation or exchange costs, would have only a small effect on the amount of revenue to be recovered from wholesale power rates (as opposed to transmission rates).

b. Classification

Classification divides the functionalized costs between capacity and energy. BPA classifies costs based on the principle of cost causation. Total costs (generation and transmission) to be recovered from wholesale power rates are classified 47 percent to capacity and 53 percent to energy.

The method for classifying costs to capacity and energy affects the distribution of costs assigned to the various customer classes and the amount of costs within each class to be recovered in the form of energy charges or capacity (demand) charges. The levels of cost allocations to each class and proportions of those costs which are identified as energy- or capacity-related can have implications for the environment.

Table II-14 contrasts the levels of capacity, energy, and total costs assigned to BPA's various customer groups under four alternative classification methodologies. These include the costs assigned in BPA's initial proposal, under a Fixed/Variable approach, LRIC classification of exchange resource costs, and LRIC classification of all costs. Capacity costs include assigned transmission costs, which were classified 100 percent to capacity in BPA's initial proposal and for each of the alternatives.

The totals in Table II-14 reflect estimated assignment of costs which would result from a Cost of Service Analysis (COSA), and which would undergo further adjustments in the rate design stage of the ratesetting process prior to development of actual rates to each customer class. However, the results presented in Table II-14 do provide a basis for evaluating the manner in which alternative classification methods would change each customer classes' costs and the associated environmental effects of those changes.

(1) Fixed/Variable Alternative

The Fixed/Variable alternative, which would classify 90 percent of all generation costs to capacity, would result in relatively higher power costs to those customers who only purchase capacity from BPA and those customer who typically maintain low load factors (ratio of average demand to peak demand). For instance, allocated costs to Firm Capacity customers for OY 1985 would be \$139 million under the Fixed/Variable alternative, compared to \$68 million in the initial proposal. Conversely, the Industrial Firm customers, who are comprised of BPA's DSI customers and who consume at high-load factors, would be allocated relatively fewer costs under the Fixed/Variable alternative, approximately \$417 million compared to \$457 million in the initial proposal. Priority Firm customers, whose loads consist of a mix of consumers, including residential consumers who tend to maintain low load factors and high load factor industrial consumers, would be allocated \$1,760 million under this alternative compared to \$1,874 million in the initial proposal.

The Fixed/Variable classification alternative assigns a significantly larger proportion of costs to capacity for the Priority Firm, Industrial Firm, and Surplus Firm customers relative to the initial proposal, assuming no rate design adjustments. These higher capacity costs would ultimately translate into higher demand charges per kilowatt, while per kilowatthour charges for energy would be much lower. The DSI customers and, to the extent that these price signals are passed through by retail utilities purchasing Priority Firm or Surplus Firm power, high load factor customers of retail utilities would benefit as a result of lower energy charges. This would have the short-run effect of encouraging increased industrial production, increased employment, and greater income levels in areas affected by industry. Corresponding increases in levels of air and water pollution and in effects to the terrestrial environment would be expected to result.

Some low load factor consumers of retail utilities would be affected. To the extent that retail utilities pass on their increased costs of wholesale capacity through increased customer charges and/or demand charges, the residential consumers would absorb higher fixed charges for basic electricity service. This would result in higher monthly bills to many residential users, and may impose a hardship on the elderly and other consumers on low fixed incomes whose total energy usage may be low, but for whom continued basic electric service may be most critical for health or other reasons.

Other impacts would arise from the fact that a Fixed/Variable approach does not adequately reflect cost causation of BPA's hydro and thermal plant mix and baseload thermal plant additions which BPA would need to meet energy load growth. Wholesale rates resulting from a Fixed/Variable classification approach would be relatively more capacity intensive, signalling consumers that energy is relatively cheap. While this may be an incentive for consumers to increase their load factor in order to avoid incurring a portion of the higher capacity charges, it would constitute a disincentive for consumers to conserve energy. In the long run, BPA would need to add baseload thermal generation at an earlier date, resulting in

increases to BPA's revenue requirement, higher wholesale rates, and localized effects to air, water, and land as a result of construction and operation of the new baseload plants.

(2) LRIC Classification of Exchange Costs

The distribution of total costs among customer groups as a result of classifying exchange resource costs using percentages developed in the initial TDLRIC Analysis (83 percent to energy, 17 percent to capacity) was not substantially different from the corresponding cost distributions developed for the initial proposal. As Table II-14 indicates, however, the costs allocated to Firm Capacity customers is approximately \$8 million less under this alternative while the costs allocated to the New Resources class is \$4 million greater. Also, the proportion of total costs accounted for by energy costs for the Priority Firm, Industrial Firm, and Surplus Firm classes is greater relative to the initial proposal. To the extent that these costs ultimately result in more energy-intensive rates to consumers, high load factor customers such as the DSI's and industrial customers of retail utilities would be somewhat more likely to cutback or shut down their operations to avoid incurring costs for additional amounts of energy usage. Therefore, this alternative could result in some loss of jobs and income to the communities in which the affected industries are located. However, an decreased industrial operation would result in improvements to the physical environment, due to decreased air emissions and water pollution.

Residential consumers of retail utilities which pass through the increased emphasis on energy charges, on the other hand, may benefit from lower customer or demand charges. Additionally, energy conservation steps would become more attractive to all consumers, due to the existence of higher charges associated with incremental energy usage.

The energy costs associated with this alternative would be likely to slow energy load growth, and may result in thermal plant additions at a slower pace than under BPA's initial proposal. However, the level capacity costs under this alternative would do less to encourage load management among consumers to hold down peak usage of electricity. Therefore, BPA may be required to install combustion turbine peaking units at an earlier date for the purpose of providing capability for meeting incremental peak loads. Operation of these units would increase noise levels and air pollution levels in their immediate areas. (Environmental effects of combustion turbines are discussed in detail in Section IV.H.6.)

(3) LRIC Classification of All Costs

The final classification alternative assumes classification of all generation costs using LRIC percentages developed in BPA's initial TDLRIC Analysis. Based on TDLRIC results, 83 percent of all hydro, thermal, and exchange costs were classified to energy under this alternative. The remaining 17 percent were classified to capacity. As Table II-14 shows, this alternative would result in relatively more costs assigned to Priority Firm, Industrial Firm, New Resources, and Surplus Firm Customers in comparison to all other alternatives. Conversely, Firm Capacity customers would be allocated significantly fewer costs under this alternative.

TABLE 11-14
COST ALLOCATIONS BY CUSTOMER CLASS FOR
BPA INITIAL PROPOSAL AND ALTERNATIVES, OY 1985
(Millions of Dollars)

Customer Class	Capacity				Energy				Total			
	Initial Proposal	Fixed/Variable	LRIC-Exchange Costs	LRIC-All Costs	Initial Proposal	Fixed/Variable	LRIC-Exchange Costs	LRIC-All Costs	Initial Proposal	Fixed/Variable	LRIC-Exchange Costs	LRIC-All Costs
Priority Firm	748	1,601	663	510	1,125	158	1,201	1,389	1,874	1,760	1,863	1,899
Industrial Firm ^{1/}	205	377	137	135	251	40	336	338	457	417	472	473
Firm Capacity	68	139	60	47	--	--	--	--	68	139	60	47
New Resource	--	--	--	--	10	2	14	14	10	2	14	14
Surplus Firm	83	159	56	55	107	17	142	143	191	174	197	198
Nonfirm Energy	5	5	5	5	--	--	--	--	5	5	5	5
Total Adjusted Rates	1,110	2,280	921	752	1,495	218	1,692	1,883	2,605	2,498	2,612	2,635
Total Costs	1,335	2,612	1,138	946	1,505	228	1,702	1,893	2,840	2,840	2,840	2,840

Source: BPA COSA and Rate Design Computer Program Output, August 1983; and BPA, Wholesale Power Rate Design Study (WPRDS) Documentation, Initial Proposal, April 1983. Note: Totals may not add exactly due to rounding.

^{1/} Does not include value of reserves credit.

Among all alternatives, the LRIC classification of all generation costs assigns the highest proportion of costs to energy for the Priority Firm, Industrial Firm, and Surplus Firm classes. Wholesale rates resulting from this alternative would be characterized by higher per kilowatthour costs for energy and lower charges per kilowatt of demand than any of the other alternatives.

Impacts under this alternative would be similar in nature to the LRIC classification of exchange costs. However, these impacts would be even more extensive under this alternative. There would be an even greater likelihood of cutbacks or shut downs by industry in response to higher energy prices. Therefore, even greater socioeconomic impacts, such as loss of jobs and incomes, would be anticipated. Positive physical impacts to the environment, such as lower levels of air and water pollution would also be expected.

Residential customers would possibly benefit from lower customer charges at the retail level. They would also be more likely to take energy conservation steps to avoid paying the higher expected energy costs.

This classification alternative would present the least incentive among all alternatives for load management, due to pricing signals which would convey low costs of capacity to consumers relative to the initial proposal. While energy consumption would likely be less than under the initial proposal, due to cutbacks in industrial consumption and greater levels of energy conservation among all consumers, there would be less incentive for consumers to hold down peak demands. Therefore, earlier additions of combustion turbines would likely be necessary. Baseload thermal plant additions probably would not be needed as soon. Relative to BPA's initial proposal, this would constitute a shift of impacts to the physical environment, such as noise and air pollution, from areas in which baseload thermal plants would have been operated to locations in which combustion turbines are installed and operated.

c. Seasonal and Diurnal Differentiation

Seasonal and diurnal differentiation are methods to send price signals which reduce peakload during BPA's peak periods and increase load in off-peak hours. In the Pacific Northwest this would result in the reduction of peaking operations at hydroelectric projects. Fluctuations in water level would be reduced. This would also reduce water temperature fluctuation in the reservoirs. Since much aquatic nesting and spawning activity is generally sensitive to both water level and temperature, environmental conditions would be improved. By improving system load factor, time-differentiation improves system operation, therefore, it can reduce the need for future construction and operation of additional facilities with attendant environmental impacts.

d. Excess Revenue Adjustment

The excess revenue adjustment determines and allocates revenue that BPA will collect from certain classes of service that is in excess of allocated costs. One of the primary sources of excess revenue is

the NF-83 Nonfirm Energy rate. Other sources of excess revenues are the DSI top quartile sales, the Capacity/Energy Exchange, the IS-83 Intertie South rate, and the ET-83 Energy Transmission rate. Allocation of excess revenue (\$290,184,000) results in a lowering of firm power rates, therefore mitigating socioeconomic effects.

e. Revenue Deficiency Adjustment

An adjustment for revenue deficiencies is necessary because rates for some services (such as Canadian Storage Power Exchange (CSPE) and Capacity/Energy Exchange) are set by contract and have not been changed. Since the costs allocated to CSPE services exceed the associated revenue, BPA would experience a revenue deficiency if the difference between the cost of providing these services and the revenue received was not collected. BPA allocates this revenue deficiency (\$78,999,000) among customers served with FBS resources. The allocation results in raising the rates of these customers.

f. Low Density Discount Adjustment

The adjustment for the Low Density Discount (LDD), offered to eligible utilities pursuant to section 7(d)(1) of the Regional Act, affects only the Priority Firm rate. Qualifying utilities receive a three, five, or seven percent discount on their Priority Firm Power purchases. The discount results in lowering the rate to qualifying utilities. If this wholesale rate discount is passed on to the retail consumers, there will be a decrease in the costs to be recovered from retail rates, therefore, mitigating the socioeconomic impacts associated with increasing power rates for the consumers of utilities with low density systems. However, since the cost of the discount is allocated to all Priority Firm customers, nonqualifying utilities' rates are higher.

g. Value of Reserves Adjustment

The DSI's provide reserves for the Federal system. Although service to the lower three quartiles of DSI service is considered "firm", BPA retains certain restriction rights. The conditions under which the DSI load can be restricted are contractually specified. BPA credits the DSI's for the value of reserves they provide by including a credit in the Industrial Firm Power rate. The resultant revenue deficiency is allocated to all firm classes of service. Having the reserves lowers the costs to other customer classes as the availability of the reserves precludes BPA from having to acquire that amount of resource. BPA passes on this cost-saving to the other customer classes. There are also positive physical environmental benefits, as measured by the avoidance of construction and operation of generation facilities, made possible by the DSI reserves.

The impact of the credit which lowers the DSI rate may be a higher level of industrial production. This may have positive socioeconomic employment benefits in the region. The impact of the allocation of the revenue deficiency (\$41,940,000) is minimized by spreading the deficiency over all BPA's firm customers.

In this document, the alternative ways of deciding the level of the credit all result in a higher value of reserves. Briefly, these alternatives include allowing a reserve credit for conservation activities, calculating the value to other customers of having the DSI's provide the reserves, and allowing the DSI's the full amount of the value rather than sharing the savings with BPA. The result of any of these alternatives would be to give the DSI's more credit, thereby lowering their rate. However, the increase in revenue deficiency, while still allocated over a large base, could have significant socioeconomic impacts by raising the other rates for firm power.

h. Adjustment for Surplus Firm Power Revenue Deficiency

Another adjustment to the allocated costs is the revenue deficiency associated with Surplus Firm Power. BPA is projected to have 730 megawatts of uniformed Surplus Firm Power in the test year. For rate-making purposes it is assumed that 335 megawatts will be sold at the fully allocated cost of Surplus Firm Power and the remaining 395 megawatts will be sold at less than its fully allocated cost. The resultant revenue deficiency (\$47,412,000) is divided into component parts and allocated to firm classes of service. The revenue deficiency associated with exchange resources is allocated to the DSI's and the remaining revenue deficiency is allocated to all other firm classes of service.

In the initial proposal, BPA assumed that the hydrosystem would be operated so that the projected surplus was levelized (uniformed) over the critical period. This results in less FBS hydrogeneration in the first year than in later years. The effects of uniforming the surplus include a lower Industrial Firm Power rate due to fewer unrecovered surplus firm power costs, and a higher Priority Firm Power rate due to increased exchange costs, being allocated to the class and higher FBS unit costs. Conversely, if BPA chose not to assume a uniform surplus, the FBS would be larger and the size of BPA's firm surplus would be increased relative to the initial proposal. The Priority Firm and Firm Capacity classes would be allocated fewer costs, due to lower unit costs of FBS resources. However, the DSI's majority share of the power costs associated with increased surplus firm power revenue deficiencies would result in a net increase of costs allocated to this class. Therefore, the DSI's would face higher rate levels relative to the initial proposal. A higher DSI rate could effect lower operating levels in periods of depressed product demand, with negative short term socioeconomic impacts. These impacts would include decreased employment and smaller tax bases within the region. There would also be positive physical impacts to air and water quality associated with decreased DSI plant operations.

i. Hanna Adjustment

Section 7(d)(2) of the Regional Act provides for a special rate consideration for which Hanna Nickel Smelting Company is eligible. The revenue deficiency caused by the Hanna Adjustment (\$1,900,000) is allocated to other firm power classes of service. The special reduced rate (IH-83) may allow Hanna to resume operation and, therefore, have a positive employment benefit of approximately 500 jobs in the region. The allocation of the revenue deficiency is over a broad enough base so as to have minimal

socioeconomic impacts on the other customers. There are negative physical impacts on air and water quality associated with the operation of the smelter as a result of this rate adjustment.

j. Revenue Stability Measures

Seven of the design elements have as an objective revenue stability (equalization of demand, billing determinants of computed requirements customers, DSI customer charge, exchange adjustment clause, supply system adjustment clause, and deferral adjustment clause). The design features are to minimize the differences between forecast and actual revenues. They are also important in assuring that an adequate revenue level is recovered from rates. The environmental impact associated with these design elements is that the costs associated with the rate period will be recovered from that rate period. Failure to do so would mean that future ratepayers could be allocated the burden of the revenue underrecovery.

(1) Adjustment for Equalization of Demand

Equalization of demand equalizes the Priority Firm and Firm Capacity demand charges. The resultant equalized demand charges are assigned to the New Resources and Surplus Firm Power rates. This discourages customers from switching between these rate schedules and therefore improves revenue stability.

(2) Billing Factors for Computed Demand

The billing factors for computed requirements customers have been modified to enhance revenue stability. Changing the billing factors to reflect BPA's obligation to provide a given level of service will compensate BPA for incurred costs. This will mitigate BPA's problem of revenue underrecovery due to displacement of firm power purchases. This rate design change will encourage computed requirements customers to take the firm power for which they have asked BPA to plan. The total power costs of these customers will increase as it will no longer be as advantageous to replace firm power purchases with, for example, their own nonfirm energy. As other customers would have been assessed the revenue underrecovery caused by the computed requirements customers, this design feature will more fairly distribute costs.

(3) DSI Customer Charge

A customer charge is proposed in this rate filing for the DSI rate (IP-83). As with computed requirements customers, BPA has experienced significant underrecovery of revenues from this customer class. This charge is based on operating demand and is set so as to insure recovery of a portion of the DSI revenues, but leave a major portion to vary with usage. This rate design element becomes a "fixed cost" to the DSI's. As long as they operate at a sufficient level to absorb the charge, BPA revenue stability will be enhanced. Also, since with the customer charge fewer revenues would need to be collected from demand and energy charges, those DSI's who operate during the rate period would have lower incremental electricity costs. However, if some DSI's only foresee a low level of operation during the rate period, they may see the customer charge as being

too high to justify operating at any level and terminate their contract with BPA. This could leave BPA with unsold power. Nonoperating industrial plants would have adverse socioeconomic effects by reducing regional employment levels and positive physical effects by lowering the levels of attendant air and water pollutants.

(4) Automatic Adjustment Clauses

An automatic adjustment clause allows rates to adjust in response to changes in the actual costs of major expense items over which a utility has little control. The automatic nature of the adjustment clause allows for increases or decreases in rates, and thus a closer tracking of costs, without the delay and expense of formal rate hearings. Two automatic adjustment clauses for the purpose of revenue stability are included in the proposed rates: the Exchange Adjustment Clause and the Supply System Adjustment Clause.

(a) Exchange Adjustment Clause

The Exchange Adjustment Clause is in the form of a rebate or surcharge if the actual average cost of selected exchange resources during the rate period differs from the forecast. The adjustment is based on the average cost of exchange resources acquired by BPA from the five nondeeming IOU's who represent 63.2 percent of the total exchange cost and 95.5 percent of the net exchange cost.

(b) Supply System Adjustment Clause

The Supply System Adjustment Clause activates if the actual OY 1984 Supply System net funding requirement for plants 1, 2, and 3 differs from the OY 1984 cost projected in the revenue requirement and if the OY 1985 annual budget for plants 1, 2, and 3 differs from the OY 1985 cost projected in the revenue requirement. The adjustment may only be triggered once.

k. Sustained Peaking Surcharge

The Sustained Peaking Surcharge is an additional charge (\$0.043 per kilowatt) to discourage customers from taking firm capacity for more than 9 continuous hours. The need for this surcharge is based on the conclusion that making capacity available for more than 9 continuous hours would adversely affect the system's ability to meet peak demand. Proposed alternatives to lengthen the time period could affect efficient operation of the Federal system and require additional peaking facilities be built and operated. This would increase the costs to be recovered from rates. There would also be physical environmental impacts on air and water quality associated with the construction and operation of additional peaking facilities.

2. Initial Proposal and Proposed Rate Schedules

BPA's existing and proposed "Wholesale Power Rate Schedules and General Rate Schedule Provisions" are included in Appendix A and B. There are 11 proposed rate schedules plus a Marketing Rate for Hanford Extension

Energy. The proposed rate schedules are designated by letters which represent the class of service to which they are applied and by numbers which represent the year of the rate filing. A summary description of these rate schedules appears in Table II-15.

The rate schedules present the services for sale, the conditions of their sale, and the applicable charges. They are a composite of the different rate design elements. The previous section described the potential environmental effects of the individual rate design elements. Table II-16 presents a summary of the projected environmental impacts of implementing the proposed rates. As such, the table represents an assessment of how the proposed combination of rate design elements might impact the environment.

A comparison of the current and proposed rates for the major rate classes is presented in Table II-17. Changes in mills per kilowatthour and percent changes in rate levels are included in the table.

3. Major Rate Alternatives

There are a number of major alternatives to the 1983 proposed wholesale power rates. These include three additional rate design alternatives (Low Water Surcharge, Transformation Charge, and a Deferral Adjustment Charge). In addition, a special irrigation rate could be offered. The Nonfirm Energy rate could be structured differently. Special rates could be developed to offer nonfirm service and the Priority Firm rate could be tiered.

a. Rate Design Alternatives

The Low Water Surcharge would be an additional charge to be applied contingent upon a system condition, such as failure to refill a reservoir. This surcharge could be applied to FBS users or, alternatively, to all firm power customers. Such a surcharge would reduce the cost of constructing and operating the system for hydrologic events with a low probability of occurrence. The overall system costs that would need recovery from FBS (or, alternatively, firm power) users would be reduced, as well as system adverse environmental impacts. When an event occurred which would trigger the surcharge, the cost of the system failure would be shared.

In the 1974 wholesale power rates, BPA assessed a transformation charge on Priority Firm and customers receiving service from BPA at voltages less than 150 kV. The charge was abolished in the 1979 wholesale power rates because BPA found that there is very little correlation between higher cost and lower voltage. Location, size, reserve capacity, chronological date of initial service, and voltage all have some impact on costs. It would be inequitable to isolate and develop a separate charge for only one of these cost indicators. BPA also stated in its 1983 Initial Proposal that the issue regarding provision of customer service facilities is best handled through a uniform customer service policy. In addition, this additional charge would eliminate many of the economic benefits of the LDD, Exchange Transmission Credit Agreement, and Residential Exchange.

TABLE II-15

PROPOSED WHOLESALE POWER RATE SCHEDULES

■ PF-83 PRIORITY FIRM RATE Available for purchase of firm power to serve loads of public agencies as well as residential exchange loads of investor-owned utilities within the Pacific Northwest Region	■ NF-83 NONFIRM ENERGY RATE Available for the contract purchase of nonfirm energy to be used anywhere
■ IP-83 INDUSTRIAL POWER RATE Available to existing direct-service industrial customers for contract purchase	■ EB-83 ENERGY BROKER RATE Applies to both sales and purchases of nonfirm power among participants in the Western Systems Coordinating Council Energy Broker System between whom agreements for energy transmission have been transacted
■ IH-83 SPECIAL INDUSTRIAL RATE Available for the Hanna Nickel Smelting Company's contract purchase of a special class of industrial power	■ RP-83 RESERVE POWER RATE Available for purchase of firm power to meet a purchaser's unanticipated load growth as provided under contract, or power for which BPA determines no other rate schedule is applicable
■ CF-83 FIRM CAPACITY RATE Available for the contract purchase of firm capacity without energy on a contract demand basis	■ NR-83 NEW RESOURCE FIRM POWER RATE Available to those investor-owned utilities under net requirements contracts for the contract purchase of firm power to be used within the Pacific Northwest Region
■ CE-83 EMERGENCY CAPACITY RATE Available for the purchase of capacity when an emergency exists on the purchaser's system or when the purchaser requests to displace higher cost firm capacity resources and BPA has capacity available	■ SP-83 SURPLUS FIRM POWER RATE Available for the contract purchase of surplus firm power to be used for resale anywhere or direct consumption
	■ SE-83 SURPLUS FIRM ENERGY RATE Available for the contract purchase of surplus firm energy to be used for resale anywhere or direct consumption except under 7(1) contracted rates

TABLE II-16

PROJECTED ENVIRONMENTAL IMPACTS
OF IMPLEMENTATION OF PROPOSED RATES

Line No.	Rate Schedule	Projected Environmental Impacts of Implementation
1.	Priority Firm Power (PF-83)	Potential positive physical impacts due to possible decreased need for construction of additional peaking capability (due to time-differentiation of rates). Promotes efficient use of FCRPS. Positive economic benefit to irrigators from addition of May to summer capacity season. Proposed alteration of billing determinants of computed requirements customers would improve BPA revenue stability and the equitable recovery of costs of resources reserved to serve these customers.
2.	Industrial Firm Power (IP-83)	Reserves provided through contract restriction rights minimize need to construct and operate additional generating resources. Impacts to DSI's, which are subject to economic conditions, include a potential for short-run negative impacts to DSI employment levels, industrial output and financial status, and short-run positive impacts to the physical environment corresponding to curtailment levels.
3.	Special Industrial Power (IH-83)	Positive impacts on Hanna employment levels without significant economic impact to other ratepayers. Negative physical environmental impacts associated with increased industrial production.
4.	Firm Capacity (CF-83)	Encourages efficient use of FCRPS; minimizes future need for construction of additional peaking facilities.
5.	Emergency Capacity (CE-83)	No significant environmental impact.
6.	New Resource Firm Power (NR-83)	No significant impact expected, due to small amount of sales anticipated under this rate schedule.

TABLE II-16, Cont.

Line No.	Rate Schedule	Projected Environmental Impacts of Implementation
7.	Surplus Firm Power (SP-83)	Potential for positive physical impacts by encouraging delayed construction and/or reduced operation of alternative resources by customers. Reduces amount of hydro resources spilled. Increases total BPA revenue, thereby enabling BPA to spread costs over a greater sales volume and hold rates down.
8.	Surplus Firm Energy (SE-83)	No significant impact anticipated as no sales are forecast under this rate schedule.
9.	Nonfirm Energy (NF-83)	Positive physical impacts due to incentive to displace high cost thermal resources. Increases total BPA revenue, thereby allowing BPA to spread costs over more sales and hold down rates. Reduces amount of hydro resources spilled.
10.	Energy Broker (EB-83)	Increases total BPA revenue, thereby minimizing other rates. Reduces amount of hydro resources spilled. Positive physical impacts due to incentive to displace high cost thermal resources.
11.	Reserve Power (RP-83)	No significant impact, due to small amount of sales anticipated under this rate schedule.
12.	Marketing Rate for Hanford Extension Energy	(Proposed payment provisions reflect continuation of present contractual arrangements, precluding any changes in payment provisions or changes in environmental consequences.)

TABLE II-17
WHOLESALE RATE SCHEDULE
AVERAGE RATES BY CLASS OF SERVICE
(mills/kWh)

Class	Current Rates	Proposed Rates <u>a/</u>	Change mills/kWh	Change Percent
	<u>(a)</u>	<u>(b)</u>	<u>(c)</u>	<u>(d)</u>
Priority Firm	18.0	22.8	4.8	26.7
Industrial Firm b/ Reserves Credit	26.7 (2.2)	27.8 (2.1)	1.2	4.9
New Resources	29.5	29.9	0.4	1.4
Surplus Firm	32.2	30.4	(1.8)	(5.6)
Nonfirm				
Standard	18.2	20.8	2.6	14.3
Spill	9.0	13.0	4.0	44.4

a/ Rates for Rate Period B, July 1, 1984 through June 30, 1985.

b/ Prior to the subtraction of the Credit for the Value of Reserves.

A Deferral Adjustment Clause would act as a safety net to guard against large revenue underruns or cost overruns occurring during the rate period. The actual level of deferral would be compared to the forecast level. If the actual level exceeded the forecast by a given threshold, a surcharge for capacity and energy would be applied to all power rates except the surplus rates. This would protect BPA from revenue underruns which would otherwise need to be collected from future ratepayers.

b. Special Irrigation Rate

BPA's initial proposal included changes in the PF-83 rate that benefit irrigators. First, the summer capacity season was redefined to include May, resulting in a low summer demand charge during a greater portion of the irrigation season. Second, BPA assigned no energy costs to the month of May. This resulted in a lower percent of energy costs to summer months compared to the seasonal differentiation method used for current rates.

One alternative to the proposed charges in the PF-83 rate is to offer a special rate equal to the Priority Firm energy rate with no demand charge. In return for elimination of the demand charge, BPA would reserve the right to interrupt service to irrigators for up to four hours in order to meet peakloads during regional capacity shortages. Compliance among irrigators with interruptions would be voluntary.

Under this proposal, irrigators would benefit from not incurring demand charges, in addition to enjoying the lower energy costs resulting from BPA's proposed treatment of May energy costs. This would probably result in higher levels of irrigation per acre and more acreage under irrigation than under BPA's initial proposal. However, in the absence of a demand charge, irrigators may not have an incentive to consume electricity during off-peak hours, and may account for additional load during BPA's peak hours. In addition, the interruptibility provisions may not be adequate to provide significant benefits to the region. First, BPA may need to interrupt service almost instantaneously due to a forced outage of one or more generating units. Notice of several hours to interrupt irrigation loads may not be practical. Second, since compliance by irrigators would be voluntary, there is no assurance of necessary additional capacity to BPA to maintain service to other firm customers. Furthermore, the load/resource balance for the rate test year shows that BPA does not require the reserves that the irrigators would provide.

A variation of the alternative would provide for instantaneous interruption of service, if necessary, to irrigators for up to 4 hours. Interruption would occur under regional capacity shortages and all forced outages. A small demand charge would be included to reflect capacity costs during peak hours and to encourage power consumption during off-peak hours. A "value of reserves" credit could be applied similar to that proposed for the DSI rate under BPA's IP-83 rate schedule. This alternative would result in additional guaranteed capacity reserves to BPA. To the extent that irrigators can shift their loads to off-peak periods, they could avoid incurring demand charges and also lessen the risk of interruption without notice. The reserves provided to the region under this alternative would

enable BPA to avoid finding alternative sources of capacity to serve other customers during peak periods. The costs of this value of reserves credit would be recovered through an increase in the Priority Firm rate.

Another alternative benefit to irrigators would be to ensure that for at least 5 years there would be no capacity charge for the off-peak hours contained in the PF-83 rate. BPA would guarantee that irrigation loads would have at least 9 hours per day during which no demand charge would be assessed. Retail utilities with irrigation loads could not apply a capacity charge during BPA's 9-hour off-peak service to that load. The effects of this rate would be to encourage off-peak electricity consumption, while making irrigation of agricultural crops more cost-effective. To the extent that irrigators shift their loads to off-peak periods, BPA's capacity requirements would be reduced. The long term guarantee features of this rate offer greater potential for long term planning and investment by irrigators.

There are a number of impacts associated with any alternative, including those discussed above, which provide for lower unit costs to irrigators. Lower energy costs to irrigators may result in less incentive to conserve than if their retail utilities were charged the full PF-83 rate to serve their loads. However, this effect would be partially offset because the rates charged nonirrigation loads would be increased to recover costs associated with a special irrigation rate. Certain features, such as a long term guarantee, may encourage investment in more efficient irrigation equipment which would otherwise not be cost-effective under standard priority firm service. Lower unit costs also provide the potential for increased farm incomes.

On the other hand, lower rates to irrigators could encourage increases in regional production of some farm commodities which are already in surplus and for which the Federal government is targeting taxpayer dollars to reduce. Also, at issue in setting a special irrigation rate is whether it is appropriate for BPA to single out a special interest group and provide rate relief for that group unless such relief has been mandated in the Regional Act or unless that group can, in return, provide tangible system benefits. The reserves that could be provided have little value to the system in the current surplus power situation. It is true that the irrigators, as a consumer class, do exhibit characteristics which are favorable to the BPA system. However, BPA's proposed rates already reflect the lower system costs associated with the summer period and with the fish operation period.

c. Alternative Structure of the Nonfirm Energy Rate

The proposed Nonfirm Energy rate (NF-83) contains rates which are applicable under varying operating and marketing conditions. These component rates are (1) the Standard rate which applies when the FCRPS hydroelectric plants are neither spilling nor forecasted to spill due to an excess of energy above available markets; (2) the Spill rate which is in effect when one or more FCRPS hydroelectric plants are spilling or forecasted to spill due to an excess of energy above available markets; (3) the Displacement rate, a share-the-savings rate equal to one-half of the sum of the purchaser's decremental savings of not generating or acquiring power from alternative resources and BPA's incremental cost of supplying the energy,

which will apply to sales of nonfirm energy when excess energy exists on the FCRPS above available markets; and (4) an Incremental rate to be applied to sales of power produced or purchased concurrently with nonfirm sales.

The excess revenue from the sales of nonfirm energy are credited to FBS, New Resources, and certain transmission costs, thereby reducing costs to be recovered from firm power rates. Therefore, any increase in revenue from nonfirm sales will likely decrease the rates to consumers. Most of BPA's export sales to the Southwest are made under the NF rate.

It is alleged that the existing rate structure has encouraged customers to wait to make their energy purchases until BPA is forced to spill water. An environmental impact as a result of the delay of purchase until BPA has spill energy for sale is that customers operate their own generation facilities for longer periods rather than displacing their power with purchases from BPA. As most of the displaceable generation is fossil fueled, the environmental effects associated with the operation of these plants is increased. Presumably, the delay in making purchases has a downward effect on retail rates with socioeconomic benefits for Southwest consumers (see also section II.B.).

An alternative to the proposed rate structure is to eliminate the Spill rate. BPA analysis (see section IV.I.2.o.) shows that elimination of the Spill rate would increase overall revenue from nonfirm energy sales and reduce much of the revenue instability caused by sales unpredictability. Customers opposing elimination of the Spill rate claim that BPA's revenue would decline due to increased competition from other utilities for nonfirm sales. In addition, elimination of the Spill Rate could result in a decrease in displacement of low-cost thermal resources if sufficient low-cost nonfirm energy is not made available. This could result in a greater amount of water spilled. Also, increased pollution levels corresponding to increased operation of coal and nuclear generating plants would result.

Another alternative to the proposed rate structure would involve delaying implementation of the Spill rate, while including a displacement rate which facilitates displacement of both coal and nuclear generation when nonfirm energy is available. This alternative rate structure would feature enough flexibility to allow displacement of low-cost thermal resources through sales under the Displacement rate and sales of nonfirm energy at the Standard rate. The Spill rate would be available when its implementation would result in more displacement of thermal resources or in greater revenue levels to BPA.

This alternative would likely result in at least as much displacement of large thermal resources as would the proposed Nonfirm Energy rate, resulting in no more, and possibly less, of an impact to air and water pollution levels from operation of thermal plants in the Pacific Northwest and the Pacific Southwest. The manner in which either the Standard rate or the Spill rate would be implemented for other nonfirm sales would maximize BPA's revenues without resulting in significantly greater amounts of water being spilled. Since this rate structure would encourage displacement of thermal resources in both the Pacific Northwest and Pacific Southwest, it would enhance incentives of Pacific Southwest utilities to initiate further Intertie

expansion. Such an expansion would increase the capability for interregional capacity and energy transactions, with additional attendant environment benefits of these transactions (see Section II.B.).

Another NF-83 issue pertains to the proposed Displacement rate. This rate, which is lower than the Spill rate, has the objective of displacing the greatest possible amount of thermal generation. It is assumed that most of the displaced thermal at the Displacement rate will be in the Pacific Northwest due to the capacity constraint of the Southwest Intertie. This rate is seen as generating additional revenue by encouraging more sales when excess energy exists. Accordingly there are both positive physical and socioeconomic benefits associated with this rate.

The Standard rate carries a 1-day guarantee of delivery of one-half of the energy BPA offers for sale. California parties argue that a multiple-day guarantee would increase the value and the utility of the energy to the Southwest customers. One-day delivery does not appear to be sufficient to allow economic shut down of fossil fuel plants because of start-up time and costs. If delivery could be guaranteed for longer times, there could be positive physical environmental impacts associated with the nonoperation of Southwest fossil fuel generation plants. However, BPA has operational difficulties with scheduling delivery of nonfirm for additional days.

d. Nonfirm Service to Industries

BPA is seeking to expand its Northwest market for nonfirm energy. One potential use of the energy is to serve alternate fuel industrial loads of BPA's utility customers. A second use is to offer nonfirm energy to the DSI's.

Alternate Fuel Industrial Loads. BPA is currently proposing nonfirm (interruptible) service to area industries which are presently relying partially or totally on alternate fuels. As proposed, this nonfirm service is made available to loads of over 2 average megawatts under the provisions of the NF-83 rate schedule. This offering of nonfirm energy could result in development of new loads that have been previously powered exclusively by alternate fuels. In addition, the availability of nonfirm service may attract industrial consumers whose firm loads have been lost to alternate fuels, or who have shut down altogether when availability of cheap alternate fuels or market for industries' product made firm service uneconomic. BPA has already begun to market nonfirm energy to six utilities for service to regional industries via contractual arrangements. The six participating utilities (industrial customers) are Umatilla Electric Cooperative (three potato processing plants), The City of Port Angeles (Crown Zellerbach paper mill), Cowlitz County Public Utility District (Longview Fibre and Weyerhaeuser mills), Tillamook County People's Utility District (Tillamook County Creamery Association), Snohomish County Public Utility District (Weyerhaeuser Kraft and Lumber Manufacturing Facility and Boeing Commercial Airplane Company), and Lewis County Public Utility District (American Crossarm Company). These industries have been able to use nonfirm energy to displace their use of natural gas, oil, or woodwastes.

To assure that sales of nonfirm energy would not displace firm service, resulting in a negative impact on BPA and retail utility

revenues, nonfirm energy would only be available to serve loads of current industrial consumers in excess of their historical firm load levels. In addition, the amount of nonfirm available to the industries' would be limited by the electrical equivalent capacity of the alternate fuel source.

Since power would be delivered to the industries by retail utilities, there would be a markup of the nonfirm at the retail level. BPA would, if necessary, take steps to facilitate agreements between the retail utility and the industry to assure that the markup recovered appropriate costs while preserving the price competitiveness of the nonfirm energy.

BPA is developing a policy to govern nonfirm service for alternate fuel industrial loads. BPA is preparing a separate Environmental Assessment to address the impacts of this policy.

Nonfirm Service to the DSI's. BPA offered a contract to the DSI's on March 22, 1983. This contract allowed each DSI to purchase any power above the level of its load as set prior to March (before the offer was made) at a cost of 11.2 mills per kilowatthour. This is the Nonfirm Energy Contract rate, and is slightly less than half the normal Industrial Firm Power rate. The term of the contract is for just over 7 months, ending on October 31, 1983. A DSI making a request for energy does so on a "take or pay" basis. That is, it must make a commitment that may not be reduced without BPA approval.

Provisions are made to allow a DSI that is already operating close to capacity, and therefore unable to purchase any appreciable amount of additional energy at the lower rate, to share in the revenues BPA will make on the sale. This is done using a formula in the contract that allows the lower rate to apply to some amount of a DSI's load that is presently billed at the higher rate; this amount increases with the total nonfirm sold by BPA. Another provision reduces the rate relief as the price of aluminum increases to very profitable levels. This phasing out begins at \$.70 per pound, and continues until all rate relief is gone at \$.85 per pound.

An alternative would extend the current contract beyond October 1983. Whether this would be possible would depend on forecasts of continued availability of nonfirm energy.

Nonfirm sales under these two arrangements (alternate fuel industries and DSI's) would increase BPA and retail utility revenue levels when sufficient nonfirm is available. Hydro resources which may otherwise be wasted would be utilized at relatively low cost by regional industries, benefitting the region's economy and displacing the use of other fuels. There could be positive physical environmental impacts on air quality from displacing alternative fuel sources (gas, oil, woodwastes). There would be some negative physical environmental impacts associated with increased industrial output. Industrial power savings could result in higher production levels which could mean positive socioeconomic benefits in the region in terms of higher employment levels and higher regional payrolls.

e. Tiered Rate Alternatives

BPA has considered tiered rates as an alternative rate design to a uniformly applied Priority Firm rate. Tiered rates involve the application of different rates to specific blocks of electricity consumed by customers. For example, the initial block of consumption could be charged a lower price than subsequent blocks. The determination of the amount of power to be sold at a lower (base) rate can depend on a variety of factors. The baseline amount may reflect an attempt to accommodate basic needs such as cooking, lighting, refrigeration, and possibly heating. For example, BPA could sell to a utility, at BPA's baseline rate, an amount of power sufficient to meet the fundamental needs of each of the utility's retail residential customers. All additional sales to that utility would then be made at the higher second tier rate. Alternatively, the base rate could reflect the relative amounts of power available from comparatively inexpensive hydropower facilities versus high cost thermal generation resources. It also could reflect a differentiation between existing load and load growth as of a given date.

Proponents of tiered rates have based their advocacy primarily on two assumed effects. First, it is claimed that a tiered rate may produce a more equitable method of cost recovery than a uniform or flat rate structure. The reasoning behind this conclusion is that customers using electricity in amounts beyond that required to meet basic needs are causing a demand for additional generation beyond that necessary to serve only basic needs. It is further argued that since this usage is presumably of a luxury nature, and since the additional generation required to meet this demand is relatively costly, the rate applied to such consumption should fully reflect the cost of the additional facilities.

The second argument advanced in favor of tiered rates is that they have a potential for encouraging conservation. It is suggested that consumers will be more sensitive to their marginal than to their average cost of electricity. Thus, a tiered rate would be presumed to produce a conservation response, relative to a uniform rate, since most consumers' marginal costs would be greater under tiered pricing than under uniform pricing. No systematic empirical evidence currently exists which would confirm a conservation effect for tiered rates at the wholesale level.

The issue of a tiered rate structure has been raised in each of the past three BPA wholesale rate filings. BPA rejected the use of a tiered rate structure in each of these filings based on both conceptual and implementation problems. As stated in the 1982 Administrator's Record of Decision (BPA, 1982a), BPA is concerned in part about the potential adverse effect of a tiered rate structure on BPA's revenue stability. A large portion of BPA's costs are fixed and do not vary as load varies. Also, a tiered priority firm rate may introduce inequities into the sale of priority firm power and could create serious cash flow problems for customers. The potential for mitigating this problem through the use of retail tiered rates may warrant investigation. In addition, in light of BPA's responsibility to provide billing credits for conservation and consumer owned renewable resources, as required by the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), a tiered rate imposed for the purpose of discouraging consumption of electricity may be redundant. Finally, tiering

the Priority Firm rate would significantly increase BPA's administrative responsibilities. For instance, there are certain difficulties inherent in billing, data collection, making appropriate calculations, determining with relative certainty whether the desired objective has been met, and reaching a prescribed revenue level. These concerns are discussed in detail in Section IV.I.3.c.

f. Marketing Rate for Hanford Extension Energy

In 1963, the Washington Public Power Supply System (Supply System) contracted with the Atomic Energy Commission (AEC) to purchase by-product steam from the operation of the New Production Reactor (NPR) at Hanford. Although the reactor was designed to produce plutonium for defense purposes, the Supply System believed that the by-product steam could be used economically for power generation. Following negotiations with Congress and the AEC, a contract for purchase of the steam was executed between the AEC and the Supply System. The Supply System subsequently constructed the Hanford Generating Project (HGP) which is a turbine generator used to convert the steam to electricity. The Supply System has been selling the power produced by the HGP to both public and private utilities pursuant to contracts executed between BPA, the Supply System, and those utilities electing to purchase Hanford energy.

In the marketing contract, a rate is needed for the share of project output to which each IOU participant is entitled. The participants are contractually required to pay an amount exactly equivalent to the Supply System's HGP costs. However, the amount of energy to be delivered varies based on the actual operation of the NPR. Consequently, no rate (in mills per kilowatthour) can be set for the power unless the rate also includes an adjustment factor so as to ensure that the participant's payment exactly equals its share of the project costs.

Historically, no rate (in mills per kilowatthour) has been set. Rather, the charge for HGP energy has been a straight pass-through of costs, i.e., the monthly payment is based on the project budget and is adjusted retroactively for actual costs. The IOU's agreed to this type of charge (or "rate") in a May 8, 1974, letter agreement with BPA. This payment methodology also is specified in Section 4 of the Hanford 1983-1993 Continued Operation Agreement (Contract No. 90944) between BPA and the Supply System.

BPA and the Supply System have already negotiated the Hanford 1983-1993 Continued Operation Agreement. The terms of the new marketing agreement are expected to be consistent with the new Continued Operation Agreement. Thus, the IOU's will be expected to pay into the BPA trust fund an amount of money equal to their share of the HGP expenses.

The payment provisions specified in the new Continued Operation Agreement extend through 1993. If the terms of the marketing agreement are consistent with the Continued Operation Agreement, there will be no changes in payment/rate provisions and therefore no changes in socioeconomic or environmental consequences.

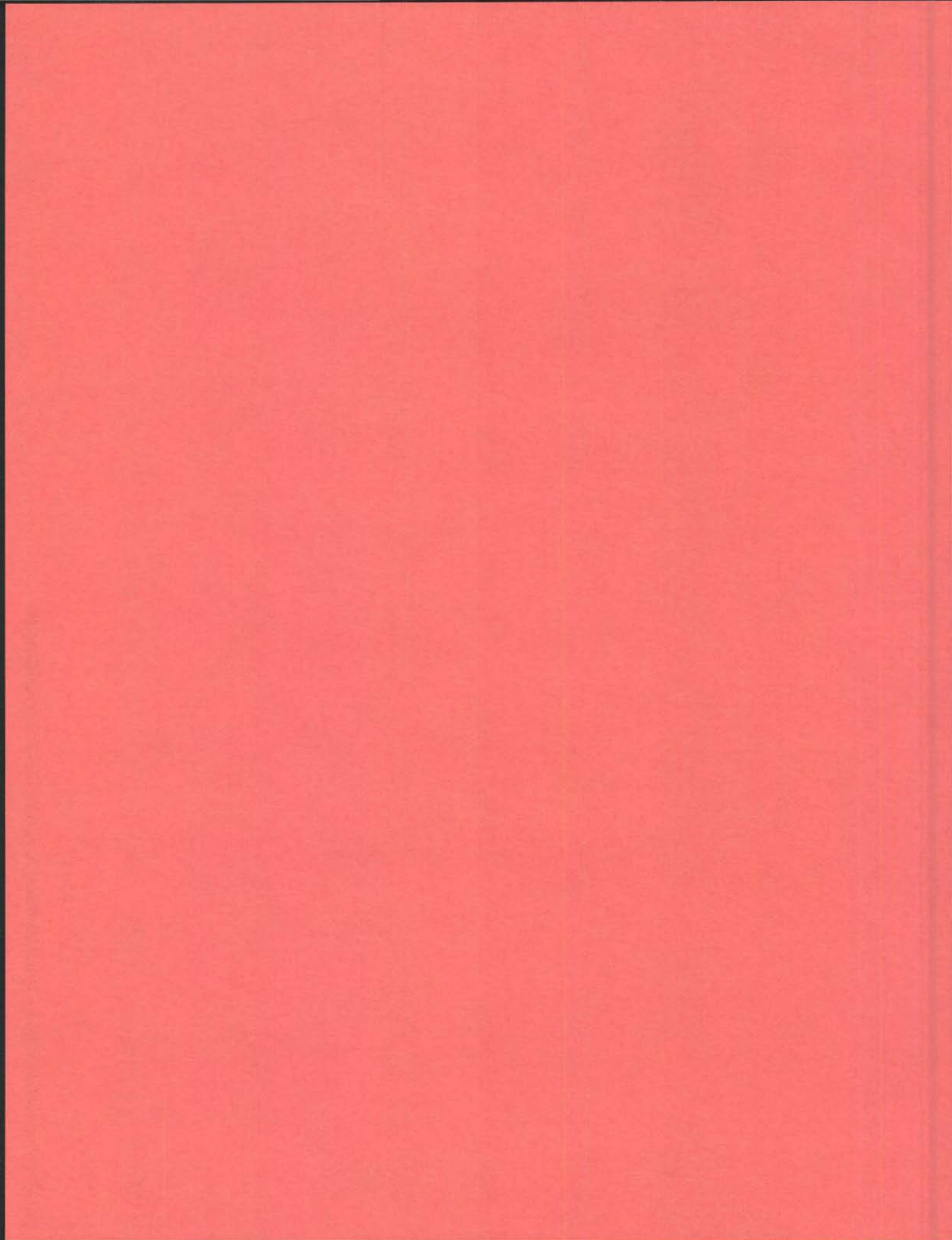
D. Consultation, Review, and Permit Requirements

In addition to their responsibilities under NEPA, Federal agencies are required to carry out the provisions of other Federal environmental laws. Most of the Federal actions related to the proposed rate adjustment discussed in this EIS do not require any particular response with regard to the resources addressed in these other Federal laws. Their requirements are more concerned with site-specific proposals and alternatives, rather than the broadly applied rate decisions being analyzed in this document.

There are a number of these Federal laws which clearly do not apply to the rate actions which BPA is currently considering. The rate proposal analyzed in this document does not recommend any actions which might jeopardize the continued existence of a listed species, a species proposed for listing, or the critical habitat of any listed or proposed species, pursuant to the Endangered Species Act. Floodplains and wetlands are protected by statutes which apply only to specific proposals for land use, resource planning, and construction and improvements. The rate proposal is not expected to convert any farmlands to other uses. Although, as discussed in the EIS, regional agricultural patterns may change in response to adjustments in power costs, the rate proposal does not contribute to the unnecessary and irreversible conversion of farmland to nonagricultural uses. BPA's wholesale rate alternatives do not include actions that are expected to adversely affect recreation resources such as wilderness areas, parks, campgrounds, trails, and scenic areas.

Chapter III

Affected Environment



III. Affected Environment

This chapter briefly describes the environment of the region and highlights those aspects that are most likely to be affected by increases in BPA's wholesale power rates.

A. Regional Setting

The Pacific Northwest region consists of the states of Washington, Oregon, Idaho, and Montana west of the Continental Divide as shown in Figure III-1 and generally defines BPA's service area. In addition, BPA sells to the Pacific Southwest nonfirm and surplus firm power that is surplus to the Northwest. While increasing wholesale power rates may have an impact on the Pacific Southwest region (those impacts are described in Section II.B.3.c.(1)(c) of this EIS), the primary impacts would be on the Pacific Northwest region. The region can be divided according to environmental similarity into 16 subareas including Western Montana as shown in Figure III-2. These subareas can be combined into 6 major areas of the region: the Puget Sound-Willamette Valley, the Columbia River Plateau, the Snake River Plateau, the Coast Range, the Cascades, and the Rocky Mountains.

The region's climate is generally mild. The area west of the Cascades is mild and wet year-round, while the area east of the Cascades typically receives no more than 15 inches of precipitation and temperatures vary more seasonally. The entire region receives less precipitation during the summer than during the rest of the year. Numerous streams, many of which feed the Snake and Columbia Rivers, offer abundant opportunities for transportation, irrigation, commercial fishing, recreation, and the production of electricity.

Half of the region is forested. West of the Cascade Range the climate is particularly well suited to the growing of trees. Three-quarters of this area is covered by forest. East of the Cascades less than one-third of the area is forested. Range and agricultural land covers the second largest portion of the region. Rangeland occupies substantial areas in the Snake River and Rocky Mountain subregions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley.

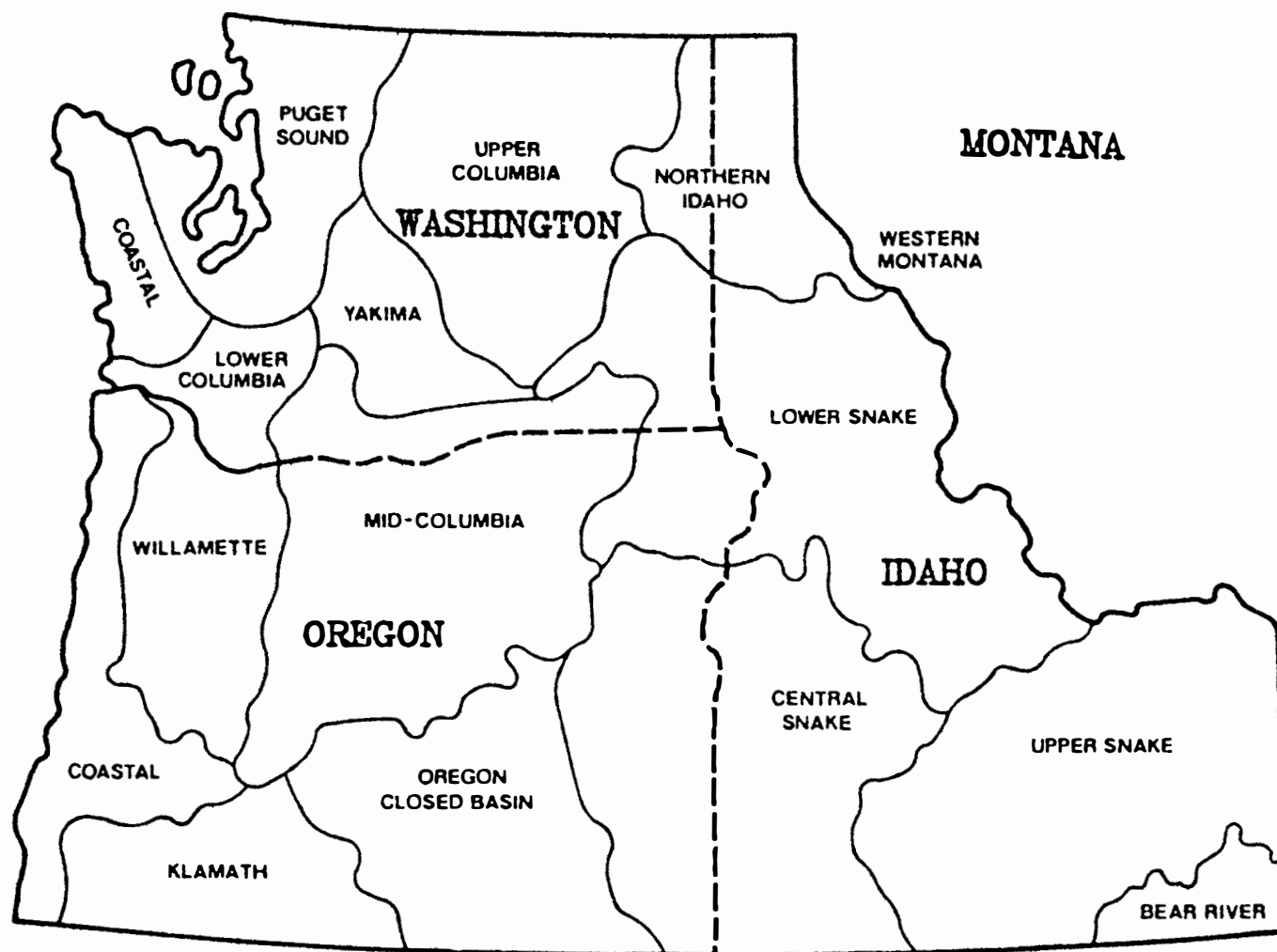
About two-thirds of the region's land is publicly owned. Half of the region's land is owned by the Federal government, and the bulk of this property is managed by the U.S. Forest Service or Bureau of Land Management for forest and range uses. State and local governments own about one-sixth of the region's land, and about one-third is privately owned.

The region's total population is about 8 million. The major population centers are Seattle-Tacoma, Portland-Vancouver, Eugene-Springfield, Spokane, and Boise-Nampa-Caldwell. During the past two decades, the region's population growth rate has exceeded the national average. Oregon and Washington have grown more rapidly than the rest of the region.

FIGURE III-1. BONNEVILLE POWER ADMINISTRATION SERVICE AREA



**FIGURE III-2.
PACIFIC NORTHWEST MAP SHOWING
MAJOR ENVIRONMENTAL SUB-AREAS**



SOURCE: BONNEVILLE POWER ADMINISTRATION

About 3 1/2 million persons are employed in the region. During the past 20 years the cyclical nature of the region's economy has caused the region's unemployment rate generally to be higher than that of the Nation as a whole. Within the region itself, Idaho usually has had the lowest unemployment rate and western Montana has had the highest. In the early 1970's, Washington had the region's highest unemployment rate as a result of the recession in the aircraft industry. Presently, the entire region is experiencing high unemployment because of the nationwide recession.

About two-thirds of the region's labor force is employed in the areas of retail and wholesale trade, services, government, and transportation. Transportation activities have been particularly important to the region's economy and involve an interstate highway system, coastal and inland water traffic, railroad lines from the regional centers to the major ports, and air transportation between the major cities.

One-fourth of the regional labor force is employed in manufacturing and construction. The largest manufacturing employers are the lumber and wood products, transportation equipment, and electronics industries, although the relative importance of these and other manufacturing industries varies considerably among the states. The availability of inexpensive electricity has been an important factor in the growth of certain industries in the region, particularly chemical and primary metal production.

The remaining portion of the region's labor force is employed in agriculture, forestry, commercial fishing, and mining. A much greater percentage of the labor force is employed in agriculture than in forestry, commercial fishing, or mining. With the construction of new irrigation facilities, more land is continually being brought into agricultural production throughout the region.

Regional electricity consumption varies geographically and seasonally. The Puget Sound-Willamette Valley subregion, which accounts for two-thirds of the region's population, uses the greatest amount of electricity. Electric energy consumption in this subregion is highest during the winter when space heating needs are greatest. East of the Cascades, electric energy use tends to be highest during the summer because of irrigation pumping and air conditioning loads.

Use of electricity in the region also varies by the type of user (see Table III-1). During 1980, the industrial sector accounted for 39.66 percent of the electric energy consumed. BPA's DSI customers accounted for 40.60 percent of the total industrial consumption. Other large industrial users are the paper products industry, which accounted for 17.54 percent of the industrial consumption and the chemical industry, which accounted for 13.57 percent. Residential and commercial users consumed 37.60 percent and 17.87 percent, respectively, of total electricity used in the region. Of the total residential consumption, single family dwellings used over 84 percent. Retail/wholesale, office, and education services accounted for over half of the total commercial consumption. Historically, the region's large supply of inexpensive hydroelectricity and limited indigenous supply of gas and oil have resulted in a much greater reliance by homes and businesses in the region on electricity for space heating than is true for the rest of the nation. Irrigation users account for 4.87 percent of the regional electric consumption.

TABLE III-1
ELECTRICITY CONSUMPTION IN THE NORTHWEST,
BY SECTOR
(1980)

Line No.	Sector	A Average Megawatts	B Percentage of Total a/
	Industrial		
1.	Food	269	4.39
2.	Lumber	549	8.96
3.	Paper	1,075	17.54
4.	Chemicals	832	13.57
5.	Metals	394	6.43
6.	DSI's	2,489	40.60
7.	Other	522	8.52
8.	Total	6,130	39.66 b/
	Commercial		
9.	Retail - Wholesale	614	22.23
10.	Office	416	15.06
11.	Auto Repair	30	1.09
12.	Warehousing	104	3.77
13.	Education Services	504	18.25
14.	Health	286	10.35
15.	Public Buildings	130	4.71
16.	Religious Services	78	2.82
17.	Hotels	130	4.71
18.	Street Lighting	82	2.97
19.	Federal agencies	80	2.90
20.	Other	312	11.30
21.	Total	2,762	17.87 b/
	Residential Total		
22.	Single Family	4,909	84.40
23.	Multi-Family	460	7.91
24.	Mobile Home	443	7.62
25.	Total	5,812	37.60 b/
26.	Irrigation	752	4.87 b/

a/ Percentages may not equal 100.0 due to rounding.

b/ Represents percent of total consumption over all sectors.

Source: Bonneville Power Administration, Division of Power Requirements,
Technical Documentation of Final BPA Forecasting Models, Appendix II to BPA
Forecasts of Electricity Consumption in the Pacific Northwest, August 1982.

The region possesses one-third of the Nation's hydroelectric potential. Of this potential, however, most economically feasible sites have already been developed. There are 58 major hydroelectric dams in the region, of which 30 are Federally owned (see Figure III-3). These Federal dams produce approximately half of the region's electricity. Regional electricity needs are also met by two nuclear plants (one Federally owned and one 30 percent Federally owned) and nine non-Federal coal plants. Six of the latter are outside of the BPA service area. One additional nuclear plant is scheduled to begin commercial operation in February 1984. Table III-2 lists the major hydroelectric and thermal generating plants in the Northwest that are currently in operation, under construction, or authorized for construction by Congress.

Approximately three-fourths of the region's bulk high-voltage transmission system is owned and managed by BPA. The system also includes interties with the Pacific Southwest and British Columbia, allowing for exchanges and power sales.

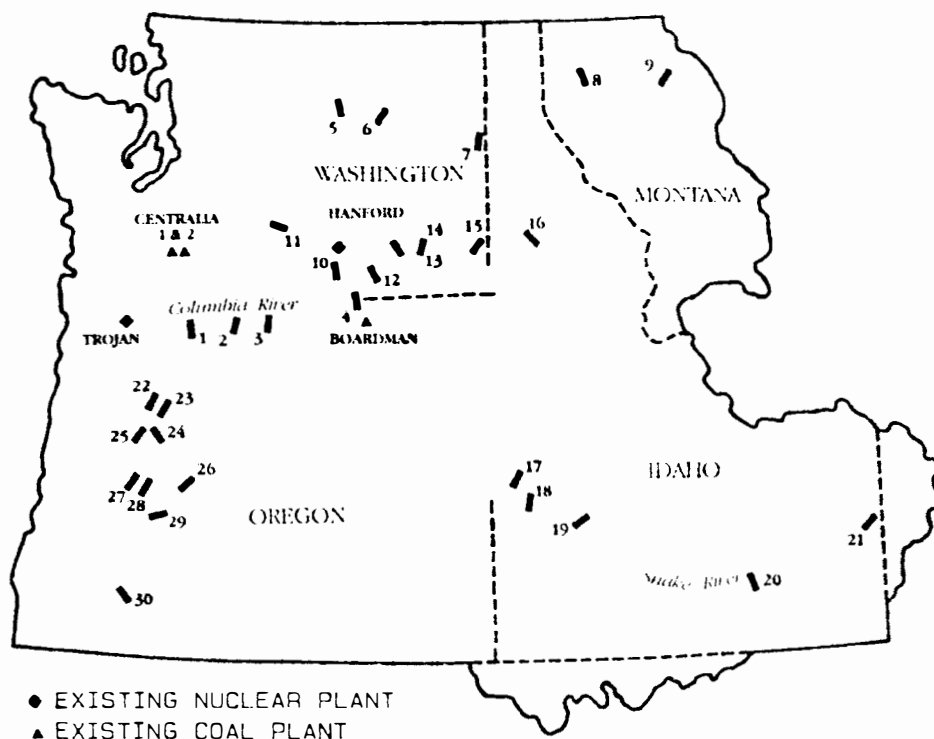
The region's electricity consumers are served by either publicly owned or investor owned utilities (IOU's). Publicly owned utilities include public utility districts, municipalities, and cooperatives. Typically, rural areas are served by publicly owned utilities while, with a few exceptions, urban areas are served by IOU's. Publicly owned utilities predominate in Washington; there are relatively few in Oregon, Idaho, and Montana.

The publicly owned utilities are BPA's largest customer class, both in number (117) and in quantity of energy purchased. During FY 1982, these customers purchased 44 percent of the electricity marketed by BPA. Many of these customers are dependent on BPA for their entire power supply, while a few own their own generation which is supplemented with purchases from BPA. Consistent with the "Preference Clause" provision of the Bonneville Project Act, BPA gives these publicly owned utilities priority access to power from the Federal base system. The Regional Act continues this preference policy and commits BPA to meeting the requirements of the publicly owned utilities.

The region's eight large IOU's accounted for 8 percent of BPA's power sales in FY 1982 exclusive of the residential exchange. These utilities either totally or jointly own generation resources. Under the Regional Act, BPA is obligated to serve the IOU's existing deficits, load growth, and a statutorily specified (Regional Act, Section 5(c)) percentage of their residential and small farm loads. Service to their residential and small farm load is by means of the residential exchange. From IOU's participating in the exchange, BPA purchases power equal to a percentage of each utility's residential and small farm load at the utility's average system cost. In turn, BPA sells the participating utility an equal amount of power at the same rate as for firm sales to preference customers. The benefits from this exchange are passed through to each utility's residential and small farm consumers.

BPA also serves two other customer classes: Federal and State agencies and direct-service industrial customers (DSI's). The Federal and State agencies constitute a very small block of BPA sales (1 percent in FY 1982) and are served under the Priority Firm rate. The DSI's accounted for

FIGURE III-3.
PACIFIC NORTHWEST REGION AND LOCATION
OF MAJOR THERMAL PLANTS AND FEDERAL DAMS



FEDERAL DAMS

1. BONNEVILLE	16. DWORSHAK
2. THE DALLES	17. BLACK CANYON
3. JOHN DAY	18. BOISE DIVERSION
4. MCNARY	19. ANDERSON RANCH
5. CHIEF JOSEPH	20. MINIDOKA
6. GRAND COULEE	21. PALISADES
7. ALBENI FALLS	22. BIG CLIFF
8. LIBBY	23. DETROIT
9. HUNGRY HORSE	24. GREEN PETER
10. CHANDLER	25. FOSTER
11. ROZA	26. COUGAR
12. ICE HARBOR	27. DEXTER
13. LOWER MONUMENTAL	28. LOOKOUT POINT
14. LITTLE GOOSE	29. HILLS CREEK
15. LOWER GRANITE	30. LOST CREEK

THERMAL PLANTS

BOARDMAN	HANFORD
CENTRALIA	TROJAN
1 & 2	

TABLE III-2

MAJOR NORTHWEST HYDROELECTRIC AND THERMAL POWER PLANTS, 1981

Line No.	Plant	A Location (stream & state)	B Total Capacity (MW)
Hydro in Operation			
1.	Bonneville	Columbia, OR-WA	1,076
2.	Chief Joseph	Columbia, WA	2,069
3.	John Day	Columbia, OR-WA	2,160
4.	Libby	Kootenai, MT	428
5.	McNary	Columbia, OR-WA	980
6.	The Dalles	Columbia, OR-WA	1,807
7.	Grand Coulee	Columbia, WA	6,263
8.	Rock Island	Columbia, WA	622
9.	Rocky Reach	Columbia, WA	1,213
10.	Boundary	Pend Oreille, WA	634
11.	Brownlee	Snake, ID-OR	548
Hydro Under Construction or Authorized for Construction			
12.	Grand Coulee PG	Columbia, WA	200
13.	John Day	Columbia, OR-WA	540
14.	Libby	Kootenai, MT	420
15.	McNary	Columbia, OR-WA	645
Nuclear in Operation			
16.	Hanford	Hanford, WA	860
17.	Trojan	Rainier, OR	1,130
Nuclear Under Construction Washington Public Power Supply System			
18.	No. 1	Hanford, WA	1,250
19.	No. 2 (Schedule to begin operation February 1984)	Hanford, WA	1,100
20.	No. 3	Satsop, WA	1,240
Coal in Operation			
Colstrip			
21.	No. 1	Colstrip, MT	330
22.	No. 2	Colstrip, MT	330
23.	Jim Bridger, No. 1, 2 and 3	Rock Springs, WY	1,500
24.	Jim Bridger No. 4	Rock Springs, WY	500
25.	Centralia No. 1 and 2	Centralia, WA	1,400
26.	Boardman	Boardman, OR	530

Source: Bonneville Power Administration, 1981, Northwest Hydroelectric and Thermal Power Plants U.S. Department of Energy, August; Bonneville Power Administration, Role Environmental Impact Statement, December 1980, p. IV-31.

26 percent of BPA's power sales in FY 1982. Among them, the aluminum industry is the largest consumer.

In addition to the above customer classes, BPA sells power outside the region (primarily to the Pacific Southwest) when it is surplus to the Northwest region needs and cannot be stored for later use. These surplus or nonfirm sales accounted for 19 percent of BPA's FY 1981 revenue and 17 percent of FY 1982 revenue. BPA sells firm capacity, surplus firm power and surplus firm energy as well to Northwest customers.

B. Areas of Particular Concern

This section identifies and describes those aspects of the existing environment that are most likely to be impacted by adjustments to BPA's wholesale power rates. The discussion of these aspects of the existing environment is divided into two sections: physical environment and socioeconomic environment.

1. Physical Environment

a. Columbia River and Tributaries

The Columbia River and its tributaries represent one of the region's major natural resources. This resource is carefully considered in this analysis because of the close association that exists between alternative uses of the resource and power production.

The Columbia River and its tributaries constitute the hydrologic system that generates the majority of the power marketed by BPA. To the extent that wholesale power rate adjustments cause changes in demand for power, operations of the dams on the Columbia River drainage may be altered, potentially influencing streamflows and water quality. Changes in river operations could, in turn, affect fish and wildlife and recreational uses of the river system. In addition, the effects of power rates on the use of electricity for irrigation farming may have implications for water quantity, air and water quality, land use, and generation requirements (see section II.B.3.f. and g.).

Generally, surface water quality in the Northwest is better than that in many parts of the country. However, water quality problems exist in some parts of the Columbia Basin, particularly on a seasonal basis. For example, one measure of water quality, dissolved oxygen content, has long been a problem in the lower Willamette River during summer months. Seasonal temperature increases are another water quality problem in the major Columbia River tributaries during periods of low flow. This condition can affect fish propagation, particularly that of salmonoids.

One water quality problem directly attributable to the dams is nitrogen supersaturation. This condition occurs in the Columbia and Lower Snake Rivers when flows exceed powerhouse capacity or levels needed for power generation and water must be spilled to regulate reservoir levels. Nitrogen supersaturation presents a threat to migratory salmonoids.

Nutrients, such as nitrates and phosphates from agricultural fertilizers, have been a major cause of excessive aquatic algal growth in the Snake and Yakima River Basins and other areas where chemical fertilizers are used in conjunction with irrigation. This condition can be remedied if water and fertilizer use are better managed and heavy flows and steep river gradients are maintained.

b. Fish

The Columbia River and its tributaries are internationally recognized for their runs of anadromous (both salmonoid and nonsalmonoid) fish and the commercial and recreational fisheries they support. 1/ Anadromous fish require access to fresh water rivers to spawn. Construction of Grand Coulee Dam on the Columbia River in 1938 limited this access for over 500 miles of the drainage above the dam. Dams also have blocked 50 percent of the Snake River to fish migration.

Impoundments of 450 miles of the Columbia River downstream from Grand Coulee Dam have eliminated salmonoid spawning except in the reach from Lake Wallula to Priest Rapids Dam (the Hanford Reach). Passage through turbines and increased migration time caused by impoundments have increased mortality of migrant juvenile fish. In addition, during high flow conditions when large volumes of water are spilled, nitrogen supersaturation creates a potentially lethal condition for fish.

Other activities such as channeling, dredging, logging, and mining have negatively impacted migratory fish by destroying natural habitat and altering water quantity and quality. Pollution from industrial, domestic, mining, and agricultural sources has lowered water quality in some areas by introducing silt, pesticides, organic wastes, and toxins. This pollution has the potential to increase fish mortality.

As a result of the variety of these negative effects, artificial propagation facilities (including hatcheries and spawning channels), fish passage facilities (for both juveniles and adults), and collection and transportation programs now are employed to maintain the present population of anadromous fish (some populations are no longer at harvestable levels). Provisions in the Regional Act will ensure that adequate programs are developed for the protection and enhancement of fish and wildlife along the Columbia River and its tributaries. The Northwest Power Planning Council, which was established under the Regional Act, has already requested and received fish and wildlife program recommendations from Federal and State wildlife agencies, Indian tribes, and other entities in the Pacific Northwest, as required under section 4(h)(2) of the Regional Act. A program for protecting, enhancing, and mitigating adverse impacts on fish and wildlife on the Columbia River and its tributaries was authorized on November 15, 1982. This program directly addresses the relationship between the development and operation of hydroelectric projects on the Columbia River and its tributaries and the protection and enhancement of fish, spawning grounds, wildlife, and wildlife habitat.

In addition to the anadromous fish population, several varieties of resident fish inhabit the Columbia River drainage. Among those of recreational importance are several species of trout (rainbow, cutthroat,

lake, brook, and brown), walleye, large- and small-mouth bass, catfish, whitefish, and landlocked populations of sturgeon. Most of the easily accessible trout waters are stocked with fish annually because natural production cannot keep pace with demand. While some reservoirs are good resident game fish producers, others have promoted the growth of undesirable fish (squawfish, carp, and suckers) or are poor fish producers because of a variety of factors.

c. Wildlife

There are a number of factors that affect wildlife species in the Pacific Northwest. Many animals, such as small birds, rodents, weasels, snakes, and frogs, have relatively small territories or ranges that are restricted by the variety, type, and abundance of cover. Beavers, muskrats, and river otters, for example, require specific vegetation for food. On the other hand, deer, elk, larger birds, and large carnivores have relatively large territories and use a variety of vegetation types. Finally, migratory animals, such as waterfowl, are influenced by weather and the availability of water and move between communities on a daily and seasonal basis.

Changes or disturbances to vegetation communities have impacts on wildlife populations. The development or abandonment of agricultural land, especially irrigated cropland, has a distinct influence on wildlife diversity and numbers. Species whose habitats are enhanced by irrigation development in the Pacific Northwest include ring-necked pheasants, gray partridges, scrub jays, leopard frogs, montane voles, and yellow-bellied marmots. Those species that tend to be adversely affected by irrigation development include sharp-tailed grouse, short-horned lizards, and various animals that depend on a shrub-steppe ecosystem.

Changes or disturbances to water areas, wetlands, and the high-yield grain crops adjacent to wetlands, contribute to an increase or decrease in waterfowl habitat. The wetlands of the region are very productive for resident species as well as for transient and/or wintering waterfowl, although many of the coastal and inland wetlands in the Pacific Northwest have been altered or destroyed by development.

Changes or disturbances to riparian vegetation are associated with shoreland construction, water level fluctuations, and shoreland erosion. Species adversely affected by loss of riparian habitat include beavers, muskrats, swallows, and kingfishers. Construction and operation of the FCRPS dams have modified much of the original riparian vegetation along the Columbia River and tributaries. In accordance with the Endangered Species Act (16 U.S.C. 1531 et. seq.), BPA alternatives examined in this document must avoid jeopardizing the continued existence of any endangered or threatened species or adversely modifying critical habitat. It is expected that none of the endangered or threatened species of the Northwest identified on the Endangered and Threatened Species List (50 CFR 17.11 and 50 CFR 17.12, January 1982) will be at risk as a result of an increase in BPA rates (see Section II.D. for an additional discussion of endangered species).

d. Recreation

The Columbia River and tributaries provide a variety of recreational opportunities for people within and outside the Pacific Northwest including fishing, swimming, boating, and, to a limited extent, rafting. Reservoirs created by the dams have enhanced swimming and boating opportunities, but have severely limited whitewater rafting. Fluctuations in reservoir levels and streamflows can impact each of these recreational activities. Finally, the enhanced habitat for bird species resulting from irrigated grain farming has improved recreational opportunities for hunters and bird watchers.

e. Land Use

(1) Irrigated Agriculture

Irrigated agriculture is the primary existing land use that could be significantly affected by adjustments to BPA's wholesale power rates. Regionwide, 8.5 million acres of farmland were irrigated in 1980. About 25.9 million acre-feet of water was used to irrigate crop and pasture lands. Estimates of irrigation water use served by surface water sources vary from 75 to 98 percent (Northwest Economic Associates, 1983). Thus, most of this water originates primarily from the Columbia River and its tributaries, including the upper and central Snake River.

The Columbia Plateau is a major dryland wheat production area of the United States. In addition, major irrigation projects on the Columbia Plateau have allowed the production of row crops including sugar beets, corn, potatoes, and beans. The Snake River Plains in Idaho is another area of extensive agricultural development, much of which is irrigated. Approximately 50 percent of the row crops in the Pacific Northwest are grown in this area. Potatoes, sugar beets, and corn are the principal crops.

(2) Direct Service Industrial Customers

Information presented in this section identifies relevant land use factors associated with the DSI's. The DSI's are dispersed throughout the tri-state area of Washington (12 plants), Oregon (7 existing plants and 1 proposed), and Montana (1 plant). The plants are located in 9 Washington counties and 5 Oregon counties. Table III-3 identifies each plant location by county.

Of the 1 proposed and 20 existing plants, 9 are located in urban settings; the other 12 (including the proposed Alumax plant in Umatilla County) are sited in or near small towns and cities in rural areas. The 12 rural regions in which DSI's are located are primarily resource oriented with land largely devoted to public, mining, forest, and agricultural uses. Table III-4 presents the population density patterns in those counties where the plants are located.

TABLE III-3
PLANT LOCATION BY COUNTY

<u>Plant/City</u>	<u>County Location</u>
<u>WASHINGTON</u>	
Alcoa/Wenatchee	Chelan
Alcoa/Vancouver	Clark (Portland-Vancouver SMSA)
Alcoa/Addy	Stevens
Carborundum/Vancouver	Clark (Portland-Vancouver SMSA)
Crown Zellerbach/Port Townsend	Jefferson
Georgia-Pacific/Bellingham	Whatcom
Intalco/Ferndale	Whatcom
Kaiser/Mead	Spokane (Spokane SMSA)
Kaiser/Tacoma	Pierce (Tacoma SMSA)
Kaiser/Trentwood	Spokane (Spokane SMSA)
Martin Marietta/Goldendale	Klickitat
Reynolds/Longview	Cowlitz
<u>OREGON</u>	
Hanna Nickel/Riddle	Douglas
Martin Marietta/The Dalles	Wasco
Oremet/Albany	Linn
Pacific Carbide/Portland	Multnomah (Portland-Vancouver SMSA)
Pennwalt/Portland	Multnomah (Portland-Vancouver SMSA)
Reynolds/Troutdale	Multnomah (Portland-Vancouver SMSA)
Elkem Metals/Portland (Formerly Union Carbide Corp.)	Multnomah (Portland-Vancouver SMSA)
Alumax (proposed)/Umatilla	Umatilla
<u>MONTANA</u>	
ARCO Metals	Flathead

TABLE III-4
COUNTY POPULATION DENSITY
1980

<u>County</u>	<u>A</u> Area Square Miles	<u>B</u> Population	<u>C</u> Population Density per Sq. Mile	<u>D</u> Percentage of Population in Urban Areas (2,500 or More)
Washington				
Chelan	2,915	45,061	15.5	44.5
Cowlitz	1,139	79,548	69.8	67.2
Jefferson	1,805	15,965	8.8	38.0
Klickitat	1,880	15,822	8.4	21.6
Pierce	1,675	485,643	289.9	83.4
Spokane	1,764	341,835	193.8	84.2
Stevens	2,468	28,979	11.7	15.6
Whatcom	2,125	106,701	50.2	55.2
Portland SMSA				
4-County Region <u>a/</u>	3,650	1,242,594	340.4	73.4
Oregon				
Douglas	5,044	93,748	18.6	42.9
Linn	2,296	89,495	39.0	49.0
Umatilla	3,217	58,861	18.3	54.7
Wasco	2,385	21,732	9.1	62.8
Montana				
Flathead	5,137	51,462	10.0	33.0

a/ Clackamas, Multnomah, and Washington counties in Oregon; Clark County in Washington.

Source: U.S. Bureau of Census, 1980 Census of Population, Volume 1, Characteristics of Population, Part 28 Montana, Part 39 Oregon, Part 49 Washington.

DSI plants are found in heavy industrial areas (9 plants), and in small, isolated industrial areas (11 plants). Those plants in heavy industrial sectors have located where zoning and infrastructure systems encourage clustering of industry. This tends to mitigate the land use impact of an individual plant. Those plant sites in rural areas are found in unincorporated areas outside of urban centers. This is due, in part, to the availability of large tracts of land for development, the separation of industrial uses from other urban uses which produce land use conflicts, as well as to tax inducements. One plant is located adjacent to a central business district.

For the most part, plant location has an insignificant impact on adjacent land uses. Most previously existing water or air pollution problems have been modified by abatement procedures. In

rural areas, land use conflicts have been reduced as the majority of plants are surrounded by undeveloped corporate lands. Also, the out-of-town location of the rurally based plants has helped to reduce plant associated traffic problems. The major impact in the rural subregions has been the trade-off of nonurban land uses, such as land available for agriculture, for urban uses.

Location requirements for manufacturing areas include direct access to commercial transportation facilities, easy commuting time to residential areas of labor force, availability of utilities, and compatibility with surrounding uses. Several aspects of specific plant location are noteworthy. Most of the plants are adjacent to water bodies of the Columbia and Willamette River systems, or Puget Sound. This reflects, in part, the need for access to waterborne transportation and/or the use of water in the industrial process. Most plants sited in rural counties have located within close proximity to the central city of the county in which they are found. Reflected in such a locational decision is the attraction of an established urban area to provide housing and other urban amenities to plant labor forces, and the availability of labor.

Plants in established industrial sectors of the large urban areas of Spokane, Tacoma, Portland, and Vancouver have responded to locational inducements of industrial areas where manufacturing uses are clustered and there is a large labor force available. Port facilities and utility infrastructure also can be shared. Plants using native raw materials often locate at the source of the materials.

The specific location of a plant affects local land use patterns by changing existing uses. New pressures on the land for community development are created to satisfy the needs and demands of plant induced population. In terms of local economic stability and employment generated, the more significant a plant is to the local economy, the more important will be the impacts on local land use patterns.

(a) Land Use Impacts on Urban Development

The main impact of the plants on land use has been to serve as a catalyst for urban growth. Plant operation has generated urban development which responded to the increased population. Continued plant operation will help to maintain the necessary threshold populations to sustain firms, institutions, and households. Threshold population is defined as the minimum population size of an urban center which will support an urban function (BPA, 1977c, p. IV-189). While it is difficult to assess how dependent land use is upon DSI operation, it can be assumed that the greater the plant contribution to the urban character of an area (as measured here by population), the greater the influence on land use.

(b) Impacts on Future Land Use

Three plants directly change land use. Mining activities at two plants (Hanna Nickle and Alcoa (Addy)) change land use as large areas of land are disturbed by mining and other plant operations. The final impact on the disturbed land is largely dependent on reclamation efforts. Impacts result from plant related traffic, especially trucks and

heavy equipment. In those areas adjacent to the mining sites, esthetic values can be diminished by plant activities (BPA, 1977c, p. IV-189). After a period of temporary shutdown, Alcoa's Addy plant presently is operating at a portion of its full capacity. Hanna's mining operations have been closed temporarily due to a depressed market and escalating production costs. However, a restart of operations at Hanna during the upcoming rate period is expected due to an increase in nickel prices and a rate structure which allows operation during offpeak hours at a reduced rate.

The third plant potentially changing land use patterns is the proposed Alumax aluminum reduction plant to be located in Umatilla, Oregon. Approximately 165 acres would be developed at this site. The construction period would strain housing and municipal services in nearby communities. Impacts to the road system, which would have to accommodate a large influx of automobile, truck, and construction traffic, are anticipated. Land use pressures would be experienced in the area as undeveloped tracts of land would be required to accept this new growth.

Although the Hanna, Alcoa, and Alumax plants could have potential impacts upon future land use, these would be small in comparison to those expected to result from continued regional population growth, changing land use patterns, and new economic developments over the next 20 years.

(c) Other Significant Natural Features

Significant natural features are abundant within the counties in which plant sites are found, as well as in adjacent counties. For example, there are State parks, State forests, National parks, National forests, National recreation areas, wilderness areas, and wildlife refuge areas in these counties.

The DSI's currently have little known impact on these areas. In the past there was fluoride induced injury to vegetation in a park adjacent to an aluminum smelting operation (ARCO Metals) as evidenced by reduced diameter growth and related insect infestation (BPA, 1977c, p. IV-158). Currently, the fluoride emission situation has improved significantly after major investment in pollution abatement equipment. Continued compliance with State standards for fluoride emissions will require further monitoring.

(d) Historic and Archeological Sites

The National Register of Historic Places lists 32 entries in cities located near DSI plant sites. No direct physical impacts upon these historical sites have been identified.

One area of known archeological sites is located near DSI customers. Approximately 100 sites are found on or near the Columbia River or the Lake River-Vancouver Lake flood plain area in Clark County, Washington (BPA, 1977c, p. IV-190). No direct physical impacts on these sites have been identified as being attributable to plants located nearby.

f. Air Quality

Federal ambient air quality standards have been established by the Environmental Protection Agency (EPA) to protect public health and welfare (Code of Federal Regulations, Vol. 40, 1981, Sections 50.4-12). Primary standards were established based on criteria for the protection of public health. Secondary standards were established based on criteria for protection of public welfare including the effects of pollutants on property, materials, and personal comfort. State agencies are permitted to establish more stringent ambient air quality regulations as well as standards for pollutants for which there are no Federal standards. Regional air pollution control agencies, such as those in Washington and Oregon, may establish standards still more stringent than the states' standards.

Air quality in the Pacific Northwest varies with the level and types of human activity present. The urban areas are often in violation of ambient air quality standards because of the concentration of vehicular and industrial activity. Some rural areas, especially in the Columbia Basin, experience high particulate concentrations as a result of wind blown dust. Factors contributing to this problem include agricultural operations, unpaved roads, and field and slash burning. There also are localized air quality problems caused by particular industrial operations. Direct combustion of wood for home heating is becoming an increasing source of air pollution. The States, through their approved air quality plans mandated by the Clean Air Act, are regulating activities to limit and in some cases to reduce air quality degradation.

Areas within the region designated in violation of one or more Federal ambient air quality standards are listed in Table III-5.

(1) Effects of Burning Wood for Home Heating and Increased Weatherization Programs

Two major activities taken by consumers recently to reduce power costs are becoming public health concerns. First, nationally, the burning of wood for home heating has more than doubled within 2 years according to a recent nationwide study (Department of Energy, 1982b, p. 4). Second, increased weatherization may affect indoor air quality. Installation of insulation, storm windows or other house tightening measures can impair the quantities of oxygen within a dwelling and increase the possibility for the build-up of dangerous gases produced by portable and solid fuel heaters, and may contribute to the concentration of indoor pollutants such as radon, formaldehyde, and respirable particulates. This oxygen depletion, accompanied with carbon monoxide gas problems, has led to a rising number of deaths across the nation (Dempewolff, 1982, p. 136). Each of these public health concerns is discussed in the sections which follow.

TABLE III-5

AIR QUALITY NONATTAINMENT
AREAS IN THE BPA SERVICE REGION a/

<u>Area</u>	Pollutants for Which Designation is Effective <u>b/</u>			
	A	B	C	D
Line No.	Total Suspended Particulate	Carbon Monoxide	Sulfur Dioxide	Ozone
<u>Idaho</u>				
1. Kellogg (Silver Valley)	unclassifiable		unclassifiable	
2. Lewiston	XX			
3. Boise		XX		
4. Pocatello	XX			
5. Soda Springs	XX			
<u>Montana</u>				
6. Anaconda Area			XX	
7. Butte Area	XX			
8. Columbia Falls Area	XX			
9. Missoula	XX	XX		
<u>Oregon</u>				
10. Portland	X	XX		XX
11. Eugene-Springfield	X	XX		
12. Salem		XX		XX
13. Medford-Ashland	XX	XX		XX
<u>Washington</u>				
14. Seattle-Tacoma	XX	XX		XX
15. Port Angeles	X			
16. Tri-Cities				
17. Spokane	XX	XX		
18. Longview	X			
19. Vancouver	XX			XX
20. Walla Walla				
21. Yakima		XX		
22. Clarkston	XX			
23. Renton	X			
24. Kent	X			

a/ This table indicates the general location of nonattainment areas. Some areas are actually quite limited in size. See Federal Register, Nov. 9, 1979, for more specific descriptions of the area boundaries.

b/ Designation "X" indicates that the area or a portion of the area violates Federal secondary air quality standard. Designation "XX" indicates that the area or a portion of the area violates Federal primary air quality standard.

Source: Code of Federal Regulations, Title 40, Protection of Environment, Part 81, U.S. Government Printing Office, Washington, D.C., revised July 1, 1981.

(a) Burning Wood for Home Heating

Wood use nationwide is estimated to be a chief fuel in 4.7 million households or 5.8 percent of the nation. Serving as either a main or secondary heating fuel when combined with use of another fuel source, the figures increase to 18.1 million households (22.3 percent). Other studies in the Pacific Northwest region identify considerably greater use of wood as a fuel source.

A random sample survey was conducted in the Portland Metropolitan Area in May 1982 to determine wood use for home heating (Cummings, 1982). The return rate on this mail survey totalled 37 percent, with 60 percent of the respondents living within the city limits of Portland. Wood is used as a primary fuel by 8.7 percent of the respondents residing in this metropolitan area, compared with a national figure of 5.8 percent. Quantities of wood burned in Portland by type of burning include woodstoves - 12 percent (burned an average of 2.3 cords per year), fireplace inserts - 9 percent (averaged 2.03 cords per year), fireplaces - 34 percent (averaged .85 cords per year). Of all those individuals surveyed, 56 percent burned an average of 1.39 cords per year, producing emissions during the 1981-82 heating season which totaled 8,474 tons of suspended particulate. Of this total, 6,512 tons emerged from the woodstoves and inserts and 1,962 tons from fireplaces.

Future use of new woodburning equipment is under consideration by one in five of Portland's respondents. Twenty-nine percent also reported that they projected burning more wood next year as compared with 63 percent who plan to burn about the same amount of wood. Two reasons may account for why the figures from this survey are higher than the national survey. First, the Portland survey was carried out in May 1982 during a period of significant economic recession as contrasted with the national survey's in-the-field period from April 1980 through March 1981. In a depressed economy, people often switch to cheaper fuel sources. Low cost woodcutting permits enabled 17 percent of the respondents to use Federal and state forests. Private and personal property sources served 39 percent and dealers sold wood to the remaining 44 percent. Second, the cost and availability of wood in the Portland area may encourage its use.

Oregon's Department of Environmental Quality (DEQ) sponsored this study because of a concern with the growing quantity of wood heating in the metropolitan area and its impact on air quality. Because of previous problems with air pollution, the State has established air quality standards in several parts of the state including Portland, Salem, and Jackson County. Air pollution programs include a vehicle emissions control program, which is based on re-licensing, and commercial and industrial emissions' standards for air, water, and certain wastes. The State established standards for woodburning stoves which would restrict the sales in urban areas, after 1985, to models which emit less than a standard emission level.

The use of wood as a heating source is not limited to urban areas. A survey conducted in July 1981 in the southern part of the State of Oregon reaching primarily small town and rural residents resulted in the following key findings:

- 52 percent had fireplaces;
- 38 percent had a woodstove;
- 24 percent heated primarily with wood;
- an average of 1.3 cords were burned in fireplaces;
- an average of 3.0 cords were burned in woodstoves;
- an average of 1.5 cords per year were burned by all surveyed respondents.

Respondents reported a 28 percent increase in wood use over the last two years and 6.1 percent indicated that they planned to buy a woodburning unit in the future.

In summary, residential wood heating is a major source of particulate pollution in Oregon and the DEQ is considering ways to combat this serious air quality problem. Figure III-4 indicates that particulate emissions from residential wood combustion now exceed those from industry in the largest metropolitan area of the state (Kowalczyk and Tombleson, November 1982, p. 10). As shown in Figure III-5, residential wood burning in Medford, Oregon, has also surpassed industrial emission trends in the generation of particulate emissions (Hough and Kowalczyk, November 1982, p. 2).

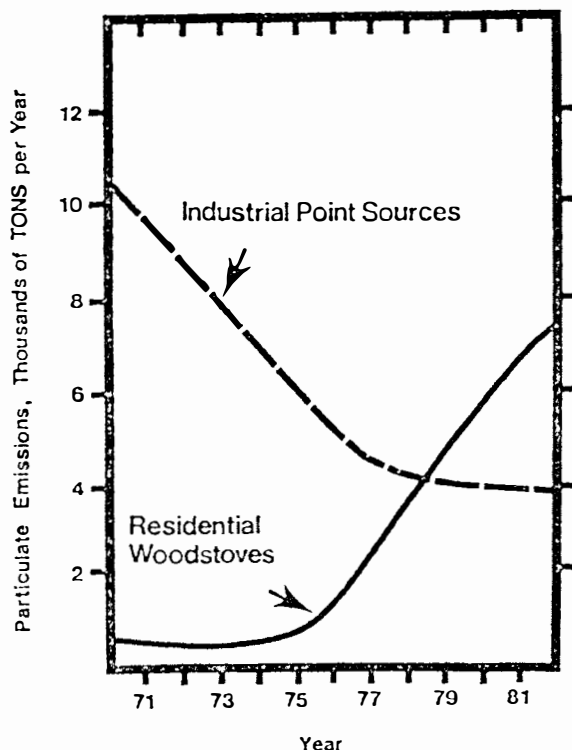
In addition to the major concern over the effect of woodburning on air quality in Oregon, woodstoves are becoming recognized as a significant fire hazard. Improper installation of woodstoves and the use of dangerous fuels in them are the two reasons why these activities have become the leading causes of fire in Oregon (Cochran, 1983). One of the primary reasons given for the greater increase in fires is the bad economy (people have been burning tires, pressed-wood logs, and other dangerous materials in woodstoves which are suitable only for wood). Creosote buildup in chimneys is a second concern to fire officials. In December 1982, one fire district in Multnomah County reported that 50 percent of all fire calls were based on woodstove chimney fires. This compares with national figures which show that these heating devices cause 22 percent of single family residential fires (*Ibid*).

The problems associated with the use of wood for home heating are, of course, not limited to Oregon. Other jurisdictions throughout the Northwest are encountering similar difficulties.

(b) Weatherization Programs and Indoor Air Quality

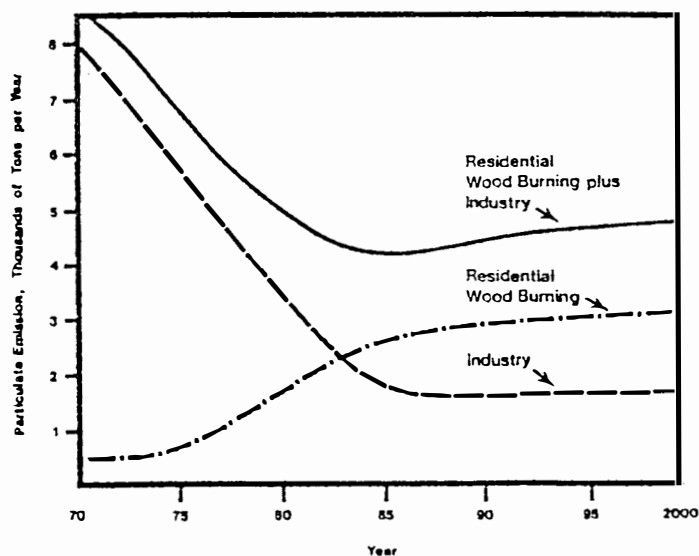
Various elements of BPA's weatherization programs have been restricted because they can alter indoor air quality which, in turn, may have implications for human health. Conservation measures that reduce the infiltration of outside air into a building (e.g., storm windows, caulking, and weatherstripping) are included in BPA's programs only on a very limited basis until their effects on indoor air quality are better understood.

FIGURE III-4:
RESIDENTIAL WOOD BURNING AND INDUSTRIAL
EMISSION TRENDS IN THE PORTLAND AIRSHED



SOURCE: JOHN F. KOWALCZYK & BARBARA J. TOMBLESON,
"A POTENTIAL WOODSTOVE CERTIFICATION PROGRAM,"
OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY,
PORTLAND, OREGON, NOVEMBER, 1982, PAGE 10.

FIGURE III-5:
RESIDENTIAL WOOD BURNING AND INDUSTRIAL
EMISSION TRENDS IN THE MEDFORD AIRSHED



SOURCE: MERLYN L. HOUGH & JOHN F. KOWALCZYK,
"A COMPREHENSIVE STRATEGY TO REDUCE RESIDENTIAL
WOOD BURNING IMPACTS IN SMALL URBAN COMMUNITIES,"
OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY,
PORTLAND, OREGON, NOVEMBER 1982, PAGE 2.

Indoor air quality is becoming a national concern, particularly in relation to making buildings energy efficient. It has been found that "air-tight" buildings tend to increase concentrations of common indoor air pollutants such as radon,, formaldehyde, and particulates. These pollutants are present to some degree in most buildings. Radon gas exists naturally in soils and migrates through foundation cracks and holes into dwellings. Formaldehyde emanates from building materials, such as particle board and plywood. Particulates are especially abundant where smoking and other combustion occur. Increasing the energy efficiency of a building, either through weatherization or reduction in mechanical ventilation, reduces the amount of inside air available for diluting indoor air pollutants. When indoor air pollutant concentrations increase, risks to human health can also increase. The health effects include increased eye and throat irritation and an increased risk of lung cancer.

Since indoor air quality is a complex and relatively new area of public concern, there are many questions to be answered about the exact effects of conservation measures on indoor air quality, and the relationships between exposure to indoor air pollutants and health effects. BPA is currently preparing an EIS on the potential health effects of a proposed nationwide weatherization program. Because there is little precise information available on which to base this EIS, BPA is also initiating three indoor air quality field studies. The first study will monitor indoor air quality in existing homes before and after weatherization. The second study will monitor indoor air quality in new-energy-efficient homes and test the efficacy of energy-efficient ventilation devices for reducing indoor air pollutants. The third study will monitor indoor air quality in commercial buildings before and after energy conservation steps have been taken. In addition to BPA's indoor air quality work, other Federal agencies and research institutes have been and are working on the problem. These include the U. S. Environmental Protection Agency (EPA), the Consumer Products Safety Commission, and the Electrical Power Research Institute. EPA has recently presented a bill to Congress specifically for funding indoor air quality research.

Methods to mitigate the effects on indoor air quality of weatherization, or house-tightening, measures are also being considered. Currently, air-to-air heat exchangers are considered to be the most efficient way to maintain existing levels of indoor air quality and still save energy. Although other mitigation devices are available and are being studied, their effectiveness is uncertain, especially for reducing concentrations of all types of indoor air pollutants.

Another mitigation strategy entails controlling or eliminating the sources of indoor air pollution. Among others, this would require the removal of formaldehyde products from buildings, the establishment of designated smoking areas to reduce exposure of non-smokers to particulates, and the sealing of all visible foundation cracks to retard the flow of radon gas into buildings. This strategy is often difficult or expensive to implement.

(2) Effect of the Direct-Service Industrial Customers

Oregon has established standards requiring that existing primary aluminum plants be retrofitted by 1984 to meet emission levels currently required of new plants. Table III-6 presents current national and state ambient air quality standards.

The evaluation of the impact of DSI customers on the terrestrial environment is based upon types of air emissions, compliance with respective State air and forage (vegetation) standards, plant locations, and local wildlife resources. Terrestrial impacts refer to effects upon natural or agricultural vegetation, wetlands, birds, mammals, reptiles, and amphibians existing within the probable impact area. Industrial plants located in urban areas were not considered to have important surrounding terrestrial resources except for ornamental vegetation.

Potential impacts of the industrial customers upon the terrestrial environment are primarily due to air emissions. Air emissions of primary concern are fluorides, particulates, sulfur dioxide, carbon monoxide, and mercury. Based upon technical information on effects of fluorides on animals, Washington, Oregon, and Montana have adopted forage standards. These standards set levels of permissible fluoride concentrations in vegetation. The forage standards and general compliance with air quality standards are used to regulate and evaluate the impacts of DSI's upon their respective terrestrial environments. Currently, the DSI's, now subject to the forage standards, are considered to have a negligible impact on their surrounding terrestrial environment.

In summary, each of the direct-service industrial customers is subject to regulation by air pollution control agencies which have established regulations to limit emissions of air pollutants from emission sources. Violations of these regulations may result in fines, variances, compliance schedules, or plant closures. Once the DSI's plants meet their respective standards for operation, it is doubtful that any significant air quality problems will be attributable directly to any of BPA's industrial customers. This conclusion is based on an analysis presented in BPA's Draft Role EIS, Appendix C (BPA, 1977c, p. IV-143).

(3) Effect of Irrigated Agriculture

It is possible that air pollution in the form of dust could be increased by a reduction in irrigated acreage. The level of air pollution would depend on whether the unirrigated land would be dry farmed, the soil structure, and on wind levels in an area.

g. Water Quality

The impact on water quality is evaluated on the basis of effluent composition and volume added to a river or marine basin. Federal and state standards for water quality apply. Individual state discharge permit conditions and monthly discharge monitoring reports are summarized by EPA for total quantities and percent contributions to the respective water basins.

TABLE III-6:
AMBIENT AIR QUALITY STANDARDS

Pollutant	National Ambient Air Quality Standards		Montana State Ambient Air Quality Standards	Oregon State Ambient Air Quality Standards	Washington State Ambient Air Quality Standards
	Primary	Secondary			
Suspended Particulates	75 ug/m³ annual geometric mean, never to be exceeded 260 ug/m³ max. 24-hour average, not to be exceeded more than once per year	60 ug/m³ geometric mean, never to be exceeded 150 ug/m³ max. 24-hour average, not to be exceeded more than once per year	75 ug/m³ annual geometric mean, never to be exceeded 200 ug/m³ 24-hour average, not to be exceeded more than once per year	60 ug/m³ annual geometric mean, never to be exceeded for any calendar year 100 ug/m³ 24-hour concentration, not to be exceeded more than 15 percent of the time for sample collected in a given calendar month 150 ug/m³ maximum 24-hour concentration, not to be exceeded more than once per year	Same as Federal Secondary Standards
Sulfur Oxides Measured as SO ₂	80 ug/m³ (0.03 ppm) annual arithmetic mean, never to be exceeded 365 ug/m³ (0.14 ppm) maximum 24-hour average, not to be exceeded more than once per year	1300 ug/m³ (0.50 ppm) maximum 3-hour average, not to be exceeded more than once per year	0.02 ppm maximum annual average, never to be exceeded 0.10 ppm 24-hour average, not to be exceeded more than once per year 0.50 ppm 1-hour average, not to be exceeded more than 18 times in any 12 consecutive months	60 ug/m³ annual arithmetic mean, never to be exceeded 260 ug/m³ maximum 24-hour average, not to be exceeded more than once per year 1300 ug/m³ maximum 3-hour average, not to be exceeded more than once per year	60 ug/m³ (0.02 ppm) annual arithmetic mean, never to be exceeded 260 ug/m³ (0.10 ppm) maximum 24-hour average, not to be exceeded more than once per year 1048 ug/m³ (0.40 ppm) maximum 1-hour concentration never to be exceeded (The Puget Sound APCA has additional standards as follows:

TABLE III-6, cont.

Pollutant	National Ambient Air Quality Standards		Montana State Ambient Air Quality Standards	Oregon State Ambient Air Quality Standards	Washington State Ambient Air Quality Standards
	Primary	Secondary			
Sulfur Oxides (cont.)					0.04 ppm maximum 30-day average, never to be exceeded 1.00 ppm maximum 5-minute average, not to be exceeded more than once in any consecutive 8 hours
Carbon Monoxides	9 ppm (10 mg/m ³) maximum 8-hour average, not to be exceeded more than once per year 35 ppm (40 mg/m ³) maximum 1-hour average, not to be exceeded more than once per year	Same as Primary	9 ppm (10 mg/m ³) maximum 8-hour average, not to be exceeded more than once per year 23 ppm maximum 1-hour average, not to be exceeded more than once per year	8.7 ppm (10 mg/m ³) maximum 8-hour average, not to be exceeded more than once per year 35 ppm (40 mg/m ³) maximum 1-hour average, not to be exceeded more than once per year	Same as Federal Primary Standards
Photochemical Oxidants	235 ug/m ³ maximum 1-hour average, measured between 10 a.m. and 4 p.m. not to be exceeded more than once per year	Same as Primary			Same as Federal Primary Standards

TABLE III-6. cont.

Pollutant	National Ambient Air Quality Standards		Montana State Ambient Air Quality Standards	Oregon State Ambient Air Quality Standards	Washington State Ambient Air Quality Standards
	Primary	Secondary			
Nitrogen Dioxide (NO ₂)	100 ug/m ³ (0.05 ppm) annual arithmetic mean, never to be exceeded	Same as Primary	0.05 ppm annual average, never to be exceeded 0.03 ppm 1-hour average, not to be exceeded more than once per year	Same as Federal Primary Standards	Same as Federal Primary Standards
Lead	1.5 ug/m ³ 90-day average, not be exceeded	Same as Primary	Same as Federal Primary Standards	Not to exceed 3.0 ug/m ³ monthly average	
Beryllium					
Fluorides, Total in air			1 part per billion parts of air (as HF), 24-hour average		
Fluorides, (as F) in forage for animal consumption dry weight basis			50 ug/g 30-day average, never to be exceeded 35 ug/g grazing season average	40 ppm average, for any 12 consecutive months	40 ppm average, for any 12 consecutive months 60 ppm each month for more than 2 consecutive months 80 ppm more than once in any 2 consecutive months Cured forage grown for sale as livestock feed shall not exceed 40 ppm by dry weight after curing or preparing for sale

TABLE III-6. cont.

Pollutant	National Ambient Air Quality Standards		Montana State Ambient Air Quality Standards	Oregon State Ambient Air Quality Standards	Washington State Ambient Air Quality Standards
	Primary	Secondary			
Fluorides, gaseous			0.3 ug/cm ² per 28 days, never to be exceeded as measured by calcium formate paper technique		3.7 ug/m ³ average as HF for any 12 consecutive hours 2.9 ug/m ³ average as HF for any 24 consecutive hours 1.7 ug/m ³ average as HF for any 7 consecutive days 0.84 ug/m ³ average as HF for any 30 consecutive days 0.5 ug/m ³ average as HF for the period through October 31 of any year
Calcium Oxide as suspended particulate				Shall not exceed 20 ug/m ³ in residential or commercial areas at any time	
Calcium Oxide as particle fallout				Shall not exceed 0.35 grams/month at any station	

Sources:

State of Montana Air Quality Rules, Montana Dept. of Health and Environmental Sciences, May 1982
 Air Quality Data Summary for Counties of King, Kitsap, Pierce, Snohomish, Puget Sound Air Pollution Control Agency, March 1, 1980
 Washington State Department of Ecology, Ambient Air Quality Standards, revised May 1982
 Oregon Department of Environmental Quality, Administrative Rules, Chapter 340, July 1982

(WP-PLA-1194m)

The state discharge permit conditions are used to determine the amount of industrial customer waste which may be discharged into their respective water resource drainage basins. Violations of these permits may result in fines, variances, compliance schedules, or plant closures.

For the aluminum plants, the water pollutants are primarily fluorides, suspended solids, acids and bases (pH), oils and greases, cyanide, chlorine, phosphorus, chromium, aluminum, organic materials, and increased temperatures. The pollutants of major concern are the fluorides, suspended solids, acids and bases, oils, and cyanide.

The chemical plants discharge mercury, chlorine, acids and bases, suspended solids, ammonia, and phosphorus. The pollutant of major concern is mercury which is very toxic to aquatic life and also hazardous to man through consumption of fish and shellfish.

The effluents of the ferroalloy plants primarily contain heavy metals such as cadmium, copper, chromium, iron, lead, titanium, and zinc. Cadmium, copper, and zinc are very toxic to aquatic life whereas iron and titanium are of lesser concern. The metallurgical plants discharge similar heavy metals (listed above), phosphorus, and oil and grease.

Major water pollutants in effluents from the carbide plants are suspended solids, oil and grease, and manganese. The pulp and paper mill effluent contains organic material, suspended solids, mercaptans, and resin acids. The above major water pollutants in sufficient quantities could impact local ambient water quality by affecting aquatic life and by presenting potential human health hazards.

The environmental effects of the major pollutants vary with the types of industry and the geographic locations in different drainage basins. DSI's having water recycling systems, with no discharge to public waters, have no impact upon water quality. Other DSI's, meeting water quality standards, contribute negligible amounts to the existing water quality problems in the region.

Irrigated agriculture also contributes to water pollution by reducing streamflow which, in turn, reduces the dilution and assimilative capacity of the stream. Irrigation runoff also increases sediment, mineral, and nutrient loads. The amount of the contribution depends on soil properties, topography, water application rates, irrigation methods, and other factors.

h. Acid Rain

Based on recent studies by the Environmental Protection Agency (General Accounting Office, 1981; Granat, et al., 1982), extensive risk from acid rain exists in the South, Southwest, in some mountain areas of the West, as well as in the well known problem regions of the Northeast and North Central United States. Emissions of both sulfur dioxide (SO_2) and nitrogen oxide (NO_x), the primary causes of acid rain, have increased dramatically in the many states located in these regions. Acid rain is defined as rainfall with a pH of less than 5.6.

There has always been some acid in natural rain, caused by such gases as the carbon dioxide from green plants which, when combined with water vapor in the air, turns to extremely weak carbonic acid. Volcanoes, forest fires and sea spray contribute small amounts of SO_2 which combines with water vapor to form sulphuric acid. Dust and airborne chemicals, such as calcium and potassium, have been able to keep the acids from natural sources relatively neutralized for many years (Howard and Perley, 1980).

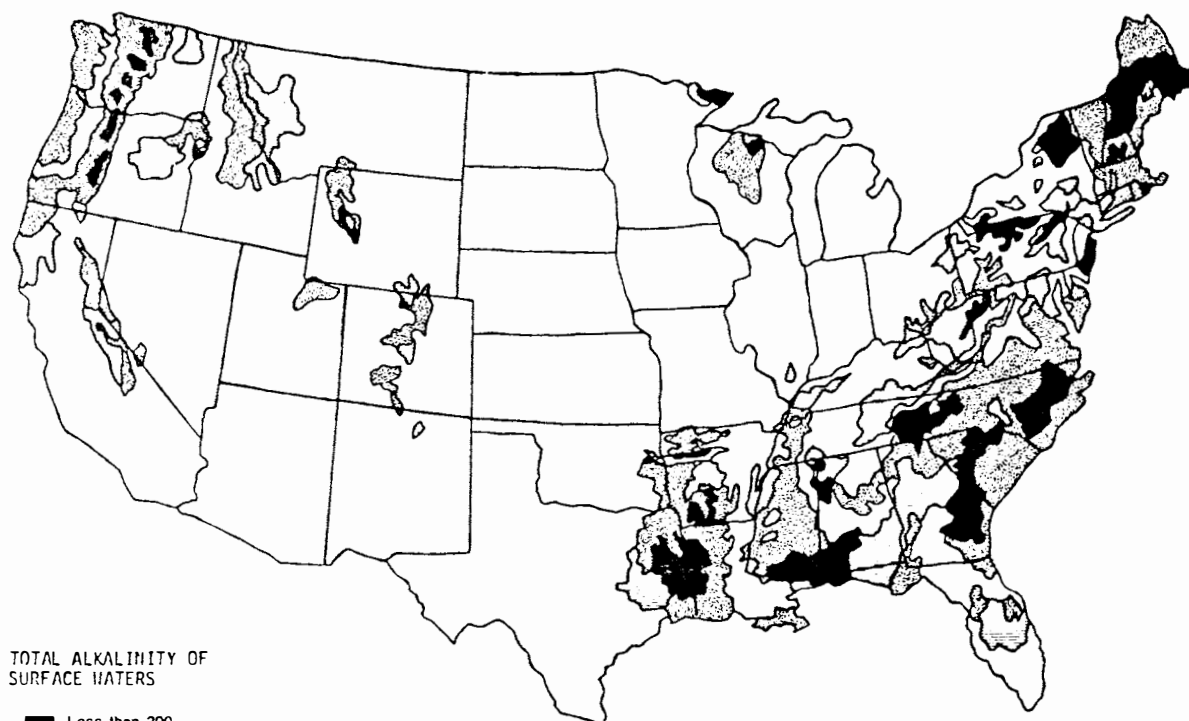
Figure III-6, displays the geographic distribution of surface water alkalinity throughout the nation and is based on surface water samples from 2,500 different sites. Since alkalinity measures indicate the ability of a watershed to withstand acid loadings, watersheds with less than 200 micro equivalents per litre alkalinity may, over years of acidic deposition, become sensitive while watersheds with less than 50 mcl may be sensitive to short term impacts from acidic deposition. Alkalinity is defined as dissolved minerals to buffer or neutralize the acid precipitation.

Many of the same geographic areas which are vulnerable to acid rain damage are also areas which receive highly acidic precipitation. Figure III-7 plots the average annual pH level of rainfall for 1979. The map identifies vulnerable areas as being those with an average annual pH level below 4.6, the threshold associated with damage to lakes. This map indicates that the acid rain levels in the Pacific Northwest have in the past been low. Figures III-6 and III-7, together, show the region to be vulnerable to change in levels of acid precipitation.

Coal-fired powerplants and other coal burning industries have been identified as a chief source of SO_2 and NO_x emissions. Considerable research has been undertaken concerning the relationship between emissions and deposition of acids and it appears clear that control of SO_2 and NO_x emissions is a vital step in mitigating the problem of acid rain. Although technology is currently available to substantially reduce coal-fired power plant emissions, the monetary costs involved have sparked debate as to whether these facilities should undergo major actions to install scrubbers and other devices. One alternative has been to transport low-sulfur coal over long distances. A variety of studies of the effects of power plants indicate the problem is growing beyond state boundaries. The effects of Southwestern power plants on the Colorado Plateau were presented to Congress (U.S. Senate Committee on Interior and Insular Affairs, 1971-72). The recognition of acid rain as a serious hazard (Likens and Bormann, 1974), as well the adverse impacts of power generation going beyond local airsheds hundreds of miles downwind, are being analyzed and discussed in many forums (Cook, 1978).

This debate over cause/effect responsibility continues because of the lack of a quantitative cause/effect relationship between pollutant emissions and the measured acidity of precipitation determined between individual and regional sources and receptor areas downwind (Record, et al., 1982). Additional work is needed to trace the release of pollutants, their conversion and transport rates, and the measurement of deposition to evaluate the effects of modification of the various source contributions on the acid precipitation in receptor areas.

FIGURE III-6. TOTAL ALKALINITY OF SURFACE WATERS



TOTAL ALKALINITY OF
SURFACE WATERS

■ Less than 200
microequivalents per litre

▨ 200-399

□ 400-599

by

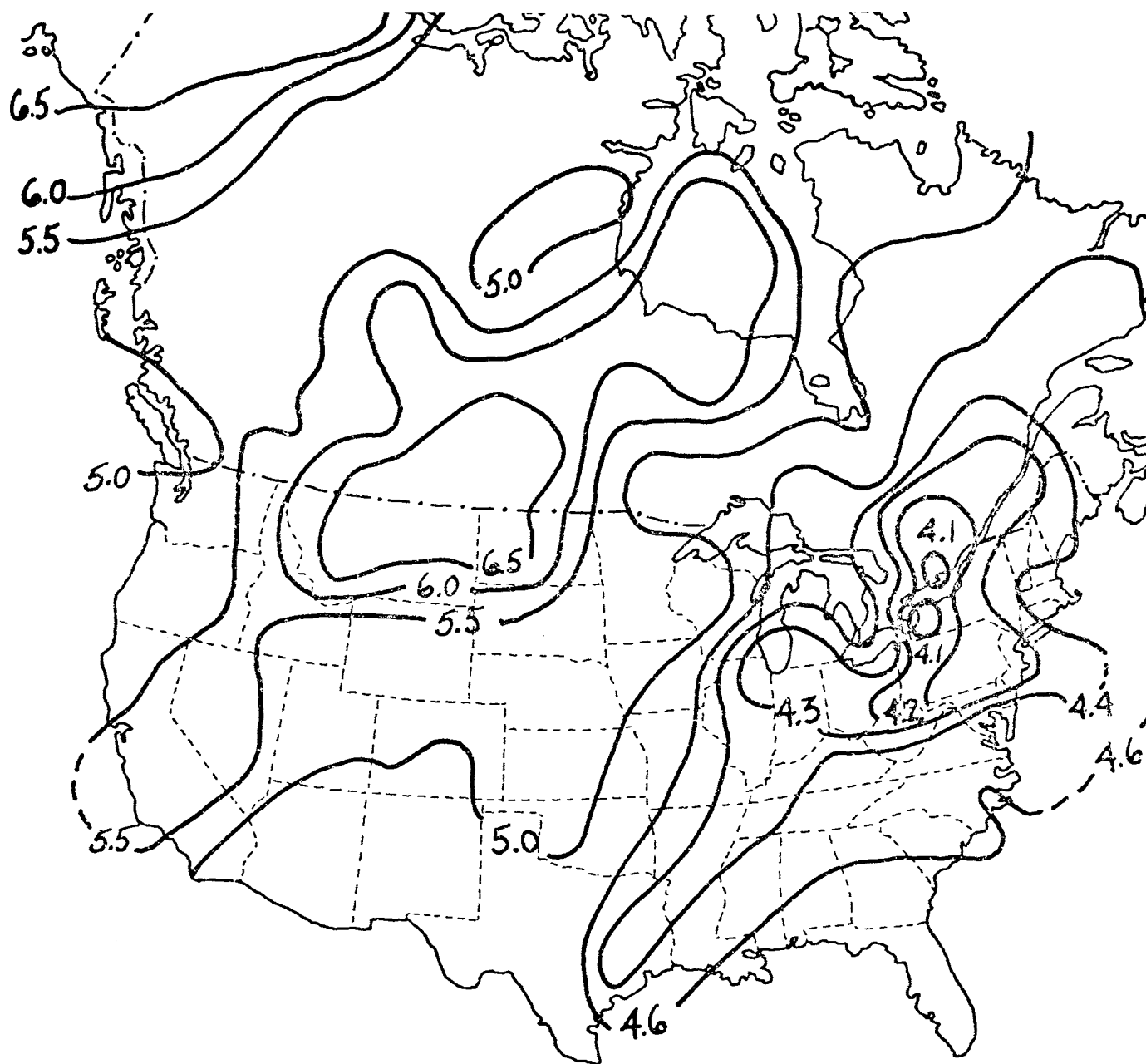
James M. Omernik and Charles F. Powers
Corvallis Environmental Research Laboratory
U.S. Environmental Protection Agency
Corvallis, Oregon 97333

November 8, 1982

The Izaak Walton League of America

1800 North Kent Street, Suite 806, Arlington, Virginia 22209

**FIGURE III-7.
AVERAGE ANNUAL pH LEVEL OF RAINFALL, 1979**



National Atmospheric Deposition Program
Precipitation-weighted NADP & CANSAP Data
February, 1981

Neutral pH 7.0
Drinking Water Standard pH.. 6.0
Normal rain pH..... 5.6
Vinegar pH..... 3.0

Eastern average annual pH level is 4.3, but some individual storms have measured as low as 3.1. Snow melts can also increase the acidity dramatically. A one digit decrease represents a ten-fold increase in acidity. More recent studies have shown that in certain western locations precipitation may be more acidic than indicated above.

Because coal fired boilers are major contributors of SO₂ emissions, the sulfur content of coal is also an important factor. A number of states in the East and Northeast sections of the country have established stringent controls on the level of sulfur which is allowed in coal for use by coal burning industries. The trend is clear: with initial support from the Environmental Protection Agency, states have passed laws and established regulations in an effort to protect air sheds and to control air pollution. However, many of these restrictions apply only to new emission sources. Without the imposition of additional controls on existing plants, it is unlikely that the problem of acid rain will decrease in the near future.

In the Pacific Northwest, two recent State actions have affected coal fired power plants. In late 1982 in the State of Washington, the Energy Facility Site Evaluation Council imposed stricter air pollution control requirements than it had recommended one year earlier, on the proposed Creston coal fired plant. The State council's requirements were tougher than the final air quality permit issued by the Region X Office of the Environmental Protection Agency. A similar issue is being debated in eastern Oregon where the Alumax aluminum plant permit is being challenged by Portland General Electric (PGE) as accounting for all allowable air pollution in this region so that proposed expansion of a nearby PGE coal fired plant would not be possible. This issue may be moot before a decision is reached, as Alumax recently announced a decision to "indefinitely defer" the planned facility.

(1) Acid Rain Effects

In light of these findings, it is worthwhile to specifically identify what acid rain does. When acid precipitation has been deposited on the ground, it may alter the composition of the soils and surface waters and exert a detrimental effect on indigenous plants and animals within the ecosystem. While understanding of all changes brought about by acid deposition is far from complete, increasing amounts of evaluated data indicate that the effects are detrimental to the environment (Record, et al. 1982). A commonly cited example of a change associated with the acidification of fresh waters is the decline and disappearance of fish populations. More subtle effects include damage to soils and reductions in crop and forest productivity. These effects can either be cumulative or can result from peak acidity episodes, such as may occur when melting "acid snows" develop during the spring runoff period. The extent and duration of environmental damage is strongly dependent upon the natural buffering capacity of the local soil.

Public health concerns are leading to evaluation of previously collected data as researchers seek to identify the effects of acid rain on people. Released in 1979, one of the first studies identified 187,686 deaths per year in the U.S. from sulphate in the atmosphere. Increased levels of sulphate in the air matched increased deaths due to all causes but particularly to heart disease. Two scientists reported "evidence that sulphates are deleterious to health . . . (and) there is no evidence of a lower threshold" which will not increase a large population's death rate (Mendelsohn and Orcutt, 1979).

(2) Conclusion

Acid rain in the Pacific Northwest could do major damage to lakes, forests, and agriculture. Oregon and Washington have taken major strides to combat increased SO₂ and NO_x emissions, by establishing air pollution standards and strict enforcement. While additional data will need to be collected on the specific emissions by coal burning industries, it is likely that a significant portion of activity to control these emissions will remain a state level function. Current Federal programs are operating under policy directives that additional research is needed before a national program of regulatory control will be established.

i. Nonrenewable Resource Consumption

While much (72 percent) of the electricity produced in the Pacific Northwest is from hydroelectric facilities, which are defined as renewable resources, the remaining electricity is produced primarily by facilities that consume nonrenewable resources. These facilities include oil and gas fired combustion turbines and coal and nuclear thermal plants.

Sub-bituminous coal and lignite reserves in the West ^{2/} are estimated by the U.S. Bureau of Mines (Department of Interior, 1974) to be in excess of 178 billion short tons. Much of the low sulfur coal reserve (approximately 82 percent) is contained in the three state Northern Great Plains region of Montana, Wyoming, and North Dakota. Approximately 31,860 tons of coal are consumed daily in the production of electricity for consumption in the Pacific Northwest. ^{3/} Sixty-four tons of nuclear fuel are used each year in the Pacific Northwest to produce nuclear generated electricity. ^{4/} Projections of uranium requirements in the western world indicate that demand will exceed production capabilities within the next decade (BPA, 1977b, Part 1, p. V-55).

Natural gas and oil generally are not indigenous to the region. Only small quantities of these resources are used for combustion turbines and other peaking units. Because of the scarcity of these fuels, electric utilities in the Pacific Northwest have not used and do not anticipate using these nonrenewable resources for baseload generation.

2. Socioeconomic Environment

BPA recognizes that the dependence of Northwest consumers on electricity varies across individual consumer classes. As a result, BPA foresees that the socioeconomic impact of higher electricity rates may be more severe for particular consumer subgroups.

a. Low-Income Residential Consumers

Social characteristics and living circumstances of low-income residential consumers in the region vary. Some low-income consumers fall into concise government income guidelines, while others have similar characteristics, but higher incomes. In effect, low-income consumers are similar only with respect to their economic position in life.

Low-income residential consumers are identified as those households whose incomes fall at or below 125 percent of the Federal government's poverty standards. The Federal standards are based on household size, the gender of head of household, and farm or nonfarm residence. These standards are adjusted periodically to reflect changes in the Consumer Price Index. Typically, households with incomes that meet the 125 percent cutoff are considered eligible for various Federal programs designed to assist low-income populations and reduce poverty. For 1975, a 125 percent poverty level income of \$5,500 was established for a nonfarm family of four. The 1981 Federal guidelines place the nonfarm four-member household poverty level at \$10,563.

As noted in BPA's 1979 Wholesale Rate Increase EIS (p. V-28), a single standard definition of the poor does not exist. Therefore, Federal poverty guidelines can be considered only as overall statistical yardsticks of poverty levels. To the extent that individual circumstances and consumption needs vary among households, a poverty income cutoff for a given low-income household may not represent the income required by other low-income households to maintain their economic well being (Department of Commerce, 1978, p. 189).

Recently published data on population levels (Department of Commerce, 1982) indicate that there are approximately 2.9 million households and 8 million persons residing in Washington, Oregon, Idaho, and Western Montana. The most recent regional data on poverty levels indicate that approximately 10 percent of the families and 13 percent of the persons in the region have incomes of less than 125 percent of the official poverty level (Table III-8). Nearly one-fifth (19.7 percent) of the elderly are in this category. Of the total number of persons in the region, 9.1 percent have incomes that are less than the poverty level income. As may be expected, smaller percentages of the population have incomes that are 75 percent of poverty level.

While it may be assumed that the low-income numbers reflected in Table III-7 are similar to today's, recent recession induced changes in the region's economy may have altered the numbers in each category. For example, the slump in the retail trade, housing construction, and wood products industries may have increased the number of households falling below poverty level standards, making poverty a more prevalent phenomenon.

The escalating costs of energy have had a more severe effect on low-income than higher income consumers. In 1979 for example, the affluent devoted on the average only 2.0 percent of their household incomes to aggregated energy costs (see Chapter IV, Section G.). In contrast, the poor spent nearly five times that percentage of their incomes for aggregated energy costs. The financial burden on the poor, and particularly the fixed income elderly poor, appears even heavier if these consumers use electricity or fuel oil for their primary heating source.

TABLE III-7

LOW INCOME POPULATION IN THE PACIFIC NORTHWEST, 1975 a/

Line No.		A		B		C	
		Income Less than 75% of Poverty Level		Income Less than Poverty Level		Income Less than 125% of Poverty Level	
		Number (000)	Percent of Total	Number (000)	Percent of Total	Number (000)	Percent of Total
1.	Families	85 (2,929)	4.3 (5.0)	137 (5,051)	7.0 (9.0)	196 (7,394)	10.0 (13.2)
2.	Unrelated Individuals	109 (2,887)	12.7 (13.9)	196 (4,891)	22.9 (23.7)	277 (6,859)	32.4 (33.2)
3.	Persons	398 (14,064)	5.4 (6.6)	674 (23,991)	9.1 (11.3)	968 (34,817)	13.1 (16.5)
4.	Elderly (65 & over)	28 (1,211)	3.7 (5.5)	84 (3,059)	11.2 (14.0)	148 (5,124)	19.7 (23.5)

a/ Numbers in parentheses indicate total U.S. poverty levels.

Source: Department of Commerce, Money Income and Poverty Status of Families and Persons in the U.S. and the West Region, by Divisions and States, 1978
Bureau of Census.

b. Direct Service Industrial Customers

(1) Economic Impacts

The 21 industrial plants served directly by BPA are an important and integral part of the economies of Oregon, Washington, and Western Montana. The plants provide employment and income for thousands of Northwest families. Secondary employment in related industries is based on this DSI production. Secondary employment is also caused by plant workers' demands for locally produced goods and services. Local merchants then hire more workers to supply these goods and services. These workers, in turn, demand additional goods and services, and the employment effects continue to "ripple" through the economy. Since most of the DSI plants are located in small communities, they account for a large share of the direct and secondary employment in these localities.

In 1981, the direct-service industrial customers provided nearly 15,000 direct jobs (Direct Service Industries, Inc., 1982) and about 52,000 secondary jobs (adapted from Department of Agriculture IMPLAN). Until late 1981, these employment figures have remained relatively stable. Since then, as a result of lowered demand for aluminum and higher operating costs, aluminum plants have reduced their number of employees.

Table III-8 identifies estimated direct and induced secondary DSI employment during 1981 by county as a percent of total county employment. The largest total direct and secondary DSI employment (26,191 workers) is in Spokane County, Washington. As a percent of total county employment, approximately 37 percent of the employment in Jefferson County, Washington, is attributable to the DSI's. About 75 percent of the total DSI employees in the Region are located in Washington.

Since the total employment supported by these plants is greater than the direct employment, the total income generated is greater than direct payrolls. DSI salaries and fringe benefits totalled \$516,607,000 in 1981 (includes Stauffer Chemical which is no longer a DSI customer). For every dollar of payroll in these industries, an estimated additional \$2.25 of income is generated for residents of the Pacific Northwest (Ibid). Thus, the total DSI direct and secondary income in 1981 was approximately \$1.679 billion of which about 90 percent originated in or from the aluminum plants. The income multiplier is lower than the employment multiplier because workers employed in secondary jobs generally receive less pay than the directly employed plant workers.

BPA's direct-service industrial customers also contribute taxes which help state and local governments provide public services. Table III-9 shows the estimated 1981 total county property taxes paid by these customers to be \$13,932,000. Plants located in Washington paid \$8,430,000 in county property taxes, those in Oregon \$2,737,000, and those in Montana \$2,373,000. The DSI's also paid more than \$36 million in other State and local taxes (no State or county totals were available). These tax monies were used to finance schools, hospitals, roads, police and fire protection, and other services. The tax amounts do not include those taxes paid by individuals.

The economic importance of the DSI's varies substantially throughout the region. Plants located in urban counties with large and diversified economies have a significant but not critical impact on county employment, income, and public services. Many of the direct-service plants, however, are located in rural counties with smaller, less diversified economies, and may have a critical impact on these variables.

As discussed in Section II.B.3.e, the DSI's serve the important function in the Northwest of providing for regional electricity reserves. The DSI's purchase approximately 25 percent of their power requirements on a nonfirm basis. The Pacific Northwest is the only region in the country in which there have been sales of energy incorporating such regional reserves. This enables the region to preclude the need to absorb the cost of otherwise spare generating facilities. These reserves have contributed as well to the lowering of overall regional power costs.

(2) Social Impacts

The social environmental components considered here in association with the DSI's, include population, community cohesion, public services, cultural and recreational resources, health care services, and occupational injuries.

TABLE III-8

DIRECT AND SECONDARY EMPLOYMENT OF
DIRECT-SERVICE INDUSTRIAL CUSTOMERS IN 1981

<u>State/County</u>	<u>A</u> <u>Direct</u> <u>Employment a/</u>	<u>B</u> <u>Secondary</u> <u>Employment</u>	<u>C</u> <u>Total Direct</u> <u>and</u> <u>Secondary b/</u>	<u>D</u> <u>Percent of</u> <u>Total County</u> <u>Employment c/</u>
Washington:				
Chelan	1,024	3,742	4,766	22
Clark	1,434	2,005	3,439	4
Cowlitz	1,280	2,339	3,619	12
Jefferson	614	1,604	2,218	37
Klickitat	614	668	1,282	20
Pierce	410	1,604	2,014	1
Spokane	3,738	22,453	26,191	19
Stevens	358	601	959	10
Whatcom	1,434	4,611	6,045	14
<u>Total</u>	<u>10,906</u>	<u>39,627</u>	<u>50,533</u>	
Oregon:				
Douglas	614	1,136	1,750	5
Linn	307	535	842	2
Multnomah	1,331	6,816	8,147	3
Wasco	512	1,403	1,915	18
<u>Total</u>	<u>2,764</u>	<u>9,890</u>	<u>12,654</u>	
Montana:				
Flathead	922	2,807	3,729	17
<u>Total</u>	<u>922</u>	<u>2,807</u>	<u>3,729</u>	
Region Total	14,592	52,324	66,916	

Note: Excludes Silver Bow County, Montana (Stauffer Chemical)

- a/ Direct employment is the number of full-time equivalent workers on the direct service plants' payrolls. The direct employment figures are based on the direct service customers' responses to a questionnaire prepared by BPA in January 1976, factored to total direct employment of 14,592 provided by Direct Service Industries, Inc., December 21, 1982.
- b/ Total direct and secondary employment is the summation of plant employment and the secondary employment generated by plant employment. The total direct and secondary employment was calculated using separate empirically determined employment multipliers for each county, based on DSI responses to a questionnaire prepared by BPA in January 1976 and a regional DSI employment multiplier estimated from the U.S. Forest Service IMPLAN Input-Output System adapted for BPA by Northwest Economic Associates.
- c/ Percentages calculated by BPA.

TABLE III-9
COUNTY PROPERTY TAXES PAID BY
BPA DIRECT-SERVICE INDUSTRIAL CUSTOMERS IN 1981 a/

<u>State County</u>	A	B
	Property Taxes Paid ((\$000))	Percent of Total County Property Taxes
Washington:		
Chelan	391	3
Clark	981	2
Cowlitz	823	3
Jefferson	249	5
Klickitat	1,276	26
Pierce	466	1
Spokane	1,241	2
Stevens	492	1
Whatcom	2,511	10
<u>Total</u>	<u>8,430</u>	
Oregon:		
Douglas	434	2
Linn	385	9
Multnomah	846	2
Wasco	1,072	8
<u>Total</u>	<u>2,737</u>	
Montana:		
Flathead	2,373	11
<u>Total</u>	<u>2,393</u>	
Regional Total	13,932	

a/ The data are based on results of a telephone survey conducted by BPA with county tax assessors in late November 1982. Percentages calculated by BPA. Whatcom County data are for 1975.

(a) Population

Opportunities for employment influence the location of population concentrations. Other factors, such as fertility rates and age structure also play a part. This section describes the population impacts of the DSI's insofar as these are a function of the amount of employment generated by the industries and some general characteristics of the persons holding jobs.

To evaluate the impacts of the DSI's on employment opportunity, both direct and secondary employment (see Table III-8) must be considered. Once the total number of jobs created by an employer is known, the number of employee dependents must be estimated. Marital status, age, education, and racial or ethnic classification bear significantly on family

size, and regional social customs or traditions influence such variables as age at marriage and family size. Data relating to these factors were available from the BPA's Draft EIS: Appendix C (BPA, 1977c) and were used to estimate the number of employee dependents for this statement.

Table III-10 shows that in 1981 total population associated with the DSI's was estimated to be 87,000 men, women, and children. The magnitude of impact differs from plant to plant in both absolute size and size relative to the population residing in the area near the plant. The heaviest numerical impact occurs in Spokane County, Washington, where more than 34,000 persons are estimated to be directly or indirectly dependent on the presence of two aluminum plants.

The DSI employment levels are presented in column C of Table III-10 as percentages of the population of the county in which each plant is located to illustrate the relative local impact of DSI employment. Although not all plant employees necessarily reside in the county of plant location, the county totals identify an approximate population density in the plant area. In 5 of the 14 counties, the DSI's provide, directly or indirectly, 10 to 18 percent of the population living in their respective counties. Population impacts approaching these percentages can be considered to bear significantly on the balance between needs for and availability of county services. Furthermore, the communities significantly impacted by the direct service industrial customers generally have populations of less than 50,000. Any major readjustment of community services and facilities could place undue strain on these smaller communities. The Spokane area, because of the sheer magnitude of people involved, constitutes perhaps the most substantial population impact of all.

The persons who indirectly derive employment from the existence of the DSI plants most likely represent a wide cross-section of the area population and do not differ in significant ways from other persons in the respective areas of plant location. The age distribution of plant employees across the "working years" is quite similar to the general population. Thus, the industrial customers do not appear to be disproportionately dependent on a particular age segment of the working population and are not likely to significantly impact the age structures of the communities in which they are located. It also would appear that the DSI's provide positions which offer relatively good security since 40 percent of their employees are 45 or older. It is likely, therefore, that a high proportion of these employees are stable, permanent residents of their communities. Interviews with community leaders and company officials are discussed in greater detail in BPA's Draft Role EIS, Appendix C, p. IV-194 (BPA, 1977c).

TABLE III-10
POPULATION IMPACTS OF BPA'S
DIRECT SERVICE INDUSTRIAL CUSTOMERS
IN 1981

<u>State/County</u>	<u>A</u> DSI-Related Population <u>a/</u>	<u>B</u> County Population <u>b/</u>	<u>C</u> Percent of Total County Population <u>c/</u>
Washington:			
Chelan	6,196	45,061	14
Clark	4,471	192,227	2
Cowlitz	4,705	79,548	6
Jefferson	2,883	15,965	18
Klickitat	1,667	15,822	11
Pierce	2,618	485,643	1
Spokane	34,048	341,835	10
Stevens	1,247	28,979	4
Whatcom	7,859	106,701	7
Total	65,694	1,311,781	
Oregon:			
Douglas	2,275	93,748	2
Linn	1,095	89,495	1
Multnomah	10,591	562,640	2
Wasco	2,490	21,732	11
Total	16,451	767,615	
Montana:			
Flathead	4,848	51,966	9
Total	4,848	51,966	

- a/ These data are based on the direct and secondary employment figures in Table III-9. Added to these is the .3 dependents per-worker figure, derived from household and labor force statistics presented in the 1980 Census of Population. The resulting total represents 1981 direct and secondary employment (plus dependents) by county, for BPA's DSI customers.
- b/ County population figures are from the U.S. Bureau of Census, 1982, 1980 Census of Population, Characteristics of Population, Vol. I, Part 28, Montana, Part 39, Oregon, Part 49, Washington.
- c/ Percentages calculated by BPA.

(b) Community Cohesion

As reported in Appendix C of BPA's Draft Role EIS (BPA, 1977c, p. IV-195), none of the BPA customers appears to have a significant impact on specific ethnic or racial segments of its community. Although some communities do have identifiable ethnic segments, the direct-service industrial customers appear to bear no special relationship to them. The responses of community officials identify the direct-service industrial customers as "good neighbors" in the community. Reports indicate that various industries have been helpful in addressing community problems and fostering community goals. Especially in the smaller communities, the industries encourage their employees to take an active, positive part in civic affairs.

In the past, the DSI's were viewed as a stabilizing influence because of their relatively consistent levels of employment. In current economic times, with employees being laid off, the value of the DSI's as a stabilizing influence in the communities has been lessened. Threatened plant closures could have a negative effect on community cohesion.

(c) Public Services

The degree of customers' impacts on fire and police protection is generally limited to the extent to which they contribute to the populations of their respective areas. Security and fire protection services for the actual plant sites are usually provided by the industrial customers themselves.

Educational services, like other social services, are impacted in proportion to the extent of population impact associated with each industrial customer. On the basis of data presented in BPA's Draft Role EIS, Appendix C (BPA, 1977c, p. IV-196), it is estimated that the ratio of school age (6-17 years) children to families is 88:100; there is an average of 0.77 families per job. Therefore, the total number of school children due to the DSI's could be approximately equal to 0.77 times the number of jobs created by the customers (66,916), multiplied by 0.88, or 45,342. For purposes of comparison, school attendance for kindergarten through twelfth grade for the State of Washington for 1980-1981 totaled 742,067 (Washington State Office of Public Instruction, 1982), while the Oregon estimate is 445,752 for the 1980-1981 school year (Oregon Department of Education, 1982). In 1981, the average per pupil cost for Washington was \$2,344, whereas that for Oregon was \$2,541. Actual costs vary from county to county, but, if educational costs associated with BPA direct-service industrial customers' generated educational needs fall between these overall State averages, the 1981 education cost impact could be estimated to range somewhere between \$105 million and \$115 million.

(d) Cultural and Recreational Resources

Because, with one exception, all of the plants considered in this analysis have been in existence for a number of years, impacts on cultural and recreational resources are primarily limited to use impacts resulting from plant induced populations. It is extremely difficult to assess the degree of resource use associated with plant populations in

regard to the numerous cultural and recreational resources available to plant employees. No excessive use problems of significance appear to be directly associated with the direct service industrial customers.

(e) Health Care Services

In this analysis, providers of health care are those people and facilities who deliver health services. These would include hospitals, nursing homes, nurses, dentists, physicians, and physician's assistants. The level of health care services in a given area is a function of the number of persons being served and the number or amount of health care resources available. A primary care physicians/population ratio of 1 to 1,250 is recommended as ideal (BPA, 1977c, p. IV-197). All of the counties in which direct service industrial customers are located appear to have adequate service, although the level of service varies considerably from county to county.

The health services system of an area usually suffers an impact if a significant number of persons migrate from the region. Since large metropolitan areas typically accommodate a number of industries, the impact associated with the loss of a single industry is not likely to be as great as a similar loss sustained in a smaller, less diversified population center. Impacts may occur in any number of ways. In an area where a particular physician may rely heavily upon industrial employment for business, the out-migration of a large number of persons could potentially force him to take his practice elsewhere. Also, the loss of tax money contributed to the general fund by an industry may result in a proportionate loss of funding for the local health care system. An associated impact could be the decline of various programs offered by the government and financed by the general fund. Examples of such programs would include alcohol rehabilitation, group homes, and well-baby clinics. Such problems potentially could be severe in smaller population centers.

The impacts on the health services system resulting from migration need not be adverse. In an area where a physician is heavily overworked, an exodus of persons could increase the availability of care to others in the area. This is, of course, true for all primary care services.

(f) Occupational Injuries and Illnesses

Another impact of the DSI company operations is the incidence of work related illnesses and injuries among their employees. The U.S. Bureau of Labor Statistics (BLS) annually conducts an occupational injury and illnesses survey in cooperation with state governments around the country. BPA obtained BLS survey data from the Washington Division of Industrial Health and Safety and the Oregon Worker's Compensation Department for Standard Industrial Classification (SIC) Code 333, Primary Smelting and Refining of Non-Ferrous Metals. (Although DSI's operate in Washington, Oregon, and Montana, corresponding information was not available from Montana due to confidentiality requirements since only one DSI plant operates in Montana). SIC 333 is the category which most closely reflects the nature of all DSI operations, and includes the more narrow SIC category 3334, Primary Smelting and Refining of Aluminum.

Combined 1981 BLS statistics for SIC 333 in Washington and Oregon, as well as nationwide statistics, are shown in Table III-11. The statistics in this table are compiled based on incidence rates per 100 full time employees using the following general formula:

$$IR = \frac{N \times 200,000}{EH}$$

where: IR = Incidence rate

N = Number of injuries and/or illnesses or lost workdays

EH = Total hours worked by all employees during the calendar year

200,000 = Base for 100 full time equivalent workers (working 40 hours per week, 50 weeks per year)

TABLE III-11

1981 OCCUPATIONAL INJURY AND ILLNESS STATISTICS
FOR STANDARD INDUSTRIAL CLASSIFICATION (SIC) CODE 333:
PRIMARY SMELTING AND REFINING OF NONFERROUS METALS

	Rate per 100 Full Time Employees a/	
	A	B
	Oregon/Washington	National
Total Recordable Cases Incidence Rate	15.1	11.3
Lost Workday Cases Incidence Rate	9.4	6.1
Lost Workday Incidence Rate	134.1	104.7

a/ Data not available for SIC 333 for Montana due to confidentiality requirements.

Source: Bureau of Labor Statistics (BLS) Survey data provided by Washington Division of Industrial Safety and Health and Oregon Worker's Compensation Department.

Table III-11 shows incidence rates for three BLS Survey elements: Total Recordable Cases, Lost Workday Cases, and Lost Workdays. Total Recordable Cases measures the number of work related injuries or illnesses resulting in fatalities, lost workdays, transfer to another job, job termination, medical treatment, loss of consciousness, restriction of work or motion, or any diagnosed occupational illnesses which are reported to the employer but are not classified as fatalities or lost workday cases. Total Lost Workday Cases include all cases in which a work related illness or injury resulted in days away from work, assignment to a temporary job, assignment to a permanent job less than full time, or assignment to a permanent job in which the employee was unable to perform all the duties normally assigned to that job. Lost Workdays are the number of lost workdays (consecutive or not) under the above criteria for lost workday cases which resulted from work related injury or illness.

As Table III-11 indicates, incidence rates for all three categories under SIC 333 were higher for Washington/Oregon than for the nation as a whole. There were 15.1 Recordable Cases per 100 full time employees in the two States, as opposed to 11.3 Recordable Cases per 100 full time employees nationwide. Lost Workday Cases and Lost Workdays per 100 full

time employees were 9.4 and 134.1, respectively, for Washington and Oregon combined. Corresponding rates for the nation were 6.1 Lost Workday Cases and 104.7 Lost Workdays per 100 full-time employees.

Additional BLS Survey data revealed that most of the Lost Workday Cases and Lost Workdays in the two States during 1981 were actual days away from work, rather than an alternative job assignment. About 53 percent of Lost Workday Cases were in the BLS Survey category Cases With Days Away From Work, while the Days Away From Work category accounted for about 68 percent of Total Lost Workdays.

Some of the recordable cases reflected in BLS data are injuries or illnesses which require medical treatment which is administered under worker compensation coverage in the state of employment. In addition, many of the recordable cases become compensable claims, or claims which result in some form of benefits paid to the worker (or worker's survivor). These include fatal injuries, injuries resulting in a specified minimum number of days away from work (e.g., 3 days in Washington, 4 days in Oregon), and disability awards (for permanent partial or permanent total disability). In 1981, Washington and Oregon collectively accepted 352 compensable claims from workers in SIC Code 333. There were 233 accepted disabling claims for the more narrow category SIC 3334 (Primary Smelting and Refining of Aluminum) in the two States during 1981.

The number of occupationally related injuries and illnesses in the region, and secondary costs associated with the various types of worker's compensation coverage, would be expected to fluctuate with the size of the workforce. However, other factors such as age of workers, experience of workers and implementation of safety measures can also affect the incidence of injuries and illnesses.

(g) Health Effects

Air and water pollutants created by BPA direct service industrial customers are described above. Air pollutants, such as suspended particulates, sulfur oxides, carbon monoxide, photochemical oxidants, hydrocarbons, and nitrogen oxides are "criteria pollutants" for which National Ambient Air Quality Standards have been established. Components of these pollutants (fluorides, mercury, ammonia, and other odorous chemicals in air) have potential health effects. The major water pollutants having potential health effects are fluorides, mercury, ammonia, chlorine, and organic wastes. Solid wastes generated by the DSI's are disposed of in approved landfills and therefore are not considered to have effects upon health. Since pollutants having health effects are controlled by Federal and state standards, the DSI's are not considered to have a significant negative environmental impact in the health area.

c. Retail Utility Industrial Customers

(1) Economic Importance

The Pacific Northwest has developed a diversity in the kinds of industries that comprise a large portion of the region's economic base. This diversity has resulted from a variety of factors. Some

industries, such as the timber and related industries, began as a result of the region's indigenous resources. Low electricity rates relative to the rest of the nation have attracted electricity intensive industries, including BPA's direct service industrial customers, to the Pacific Northwest. More recently, industries such as electronics have grown in the Pacific Northwest, attracted by the quality of the labor force and the quality of life in the region.

While the region's aluminum plants and other large industrial companies comprise BPA's DSI customers, the balance of the Pacific Northwest's load is served by public and private retail utilities. These industries vary in their size and energy-intensiveness. Collectively, the industrial customers of the region's retail utilities consumed about 60 percent of the region's industrial electricity load, with the balance accounted for by the DSI's (see Table III-1). However, the non-DSI's share of total manufacturing direct employment in the region is much greater. Manufacturing employment in 1980 is summarized in Table III-12 by major industry. Total 1981 direct employment by the DSI's was 14,592 (Table III-8). As Table III-12 indicates, total direct employment for the manufacturing industries in the region in 1980 (one year earlier) was over 550,000. Therefore, industrial customers of public and private agencies account for well over 95 percent of direct employment in Pacific Northwest manufacturing industries. In addition, these industries generate additional income and employment due to the multiplier effect discussed in the previous section relating to DSI employment (Section III.B.2.b(1)).

(2) Overview of Major Industries

(a) Lumber and Wood Products

Lumber and wood products is the major manufacturing industry in the region. Not only is it the largest employer in manufacturing, but the industry's demand for machinery creates jobs in the fabricated metals and machinery categories, and residual wood wastes supply raw materials to the pulp and paper industries. The wood products industry is not an electricity-intensive industry, but its size in the region causes it to be the fourth largest industrial consumer of electric energy.

In 1979, the regional wood products industry accounted for 38 percent of U.S. lumber production and 55 percent of U.S. softwood plywood production. The bulk of production, almost 20 percent of U.S. lumber production and over 40 percent of U.S. softwood plywood production, occurred in Oregon. Furthermore, a large proportion of production in both Oregon and Washington is west of the Cascades.

In 1980, 139,100 persons were employed in Lumber and Wood Products (SIC 24). Of these, approximately 37 percent were employed in Lumber (SIC 2421) and approximately 19 percent in Plywood (SIC 2436). It is estimated that their respective 3-digit SIC categories accounted for 48 and 36 percent of the 1977 electricity consumption by the lumber and wood products industry (Synergic Resources Corporation, 1981).

Table III-12

Manufacturing Employment in the Pacific Northwest
By Industry in 1980

<u>Industry</u>	<u>Number Employed</u> (000)	<u>Share of Total</u> (Percent)
Food and Kindred Products	73.1	12.4
Lumber and Wood Products	139.1	23.6
Pulp and Paper Products <u>a/</u>	30.1	5.1
Chemicals and Allied Products <u>a/</u>	13.8	2.3
Primary Metals <u>a/</u>	31.2	5.3
Transportation Equipment	109.3	18.6
Electronics	86.4	14.7
Other Manufacturing	105.8	13.0
Total Manufacturing	558.8	100.0

a/ Includes DSI employment.

Source: Northwest Power Planning Council, Economic and Demographic Assumptions, Revised Draft, December 10, 1982b, p.9.

The lumber and wood products industry is currently at depressed levels, experiencing employment 15.7 percent lower in 1980 than the recent peak of 165,000 employees in 1978. The primary cause of this situation is the depressed housing market resulting from high interest rates. U.S. housing starts reached 2.023 million units in 1978. By 1980, housing starts had dropped to 1.303 million units.

Many analysts in the region feel that the outlook for the region's lumber and wood products industry is not bright, even after the current recession passes. National forecasts of housing starts indicate that demand will not reach the levels experienced in the late 1970's. For example, DRI projected that U.S. housing starts would reach a level of 1.98 million units by 1986, then gradually decrease to an average 1.6 million units during the 1990's (Data Resources, Inc., 1982). The primary reason is the cost and affordability of housing in the future. The impacts on the lumber and wood products industry are increased because housing units are projected to be smaller in size, on the average, requiring less wood products per unit.

In addition, the region's lumber industry has experienced increasing competition from the Southeastern lumber producing areas. Higher transportation, labor, and stumpage costs make it difficult for the Pacific Northwest to retain market shares. One major difference between timber resources in the Southeast and the Pacific Northwest lies in the ownership of timber stands. In the Southeast region, timber resources are owned primarily by lumber industry and other private concerns. The timber harvest can respond to fluctuations in demand, relieving pressure on stumpage

prices. Relatively favorable supplies and less rugged terrain in plantation grown pine stands contribute to lower stumpage costs in the Southeast compared to the Pacific Northwest.

In 1977, estimated softwood timber resources in Washington and Oregon were owned by the U.S. Forest Service (53 percent), the lumber industry (19 percent), other public agencies (19 percent), and other private parties (9 percent) (Congressional Budget Office, 1980). Timber resources under the management of the U.S. Forest Service are governed by laws limiting harvests to levels sustainable in perpetuity, with specified exceptions. Stumpage prices have been competitively bid in the past, raising costs dramatically to some mills who rely extensively on timber from National Forest lands. Therefore, portions of the timber resource in the region are limited by regulation. Some level of uncertainty exists regarding these limits, however. These are affected by such factors as the budgetary resources of the Forest Service, changes in the estimates of current and future timber resources, changes in the laws governing management of the resources, or adoption of exceptions to sustainable yield provisions specified in current legislation.

Another area of uncertainty is the export of logs or wood products. Most of the region's exports go to Japan in the form of logs. This has been opposed by mill owners who fear the loss of raw materials for production and potential markets for their products. The potential for expanding markets in lumber and wood products in Pacific Rim countries and other importing countries exists, but represents an area of uncertain magnitude.

Major considerations identified by the Northwest Power Planning Council (i.e., Northwest Power Planning Council, 1982. p. 14) which affect the forecast of employment and production in the lumber and woods products industry include (1) levels of timber harvest in the region; (2) national demand for wood products, particularly in housing; (3) changes in production processes, including those which change the output per employee, or yield per cubic foot of log; (4) shifts in type of wood products produced; (5) competition for market with other regions of the U.S. and Canada; and (6) export of logs and wood products to Japan or other countries.

(b) Pulp and Paper Industry

The pulp and paper industry is the second largest industrial consumer of electricity in the Pacific Northwest. In 1980, firms in pulp and paper products accounted for 18 percent of the electricity consumed by industry (Table III-1). Although a large consumer of electricity relative to other industries, a recent survey of regional mills showed that less than 15 percent of total energy consumed was purchased electricity (American Paper Institute, 1982).

In 1980, 30,100 persons were employed in the pulp and paper industry (SIC 26). Of these; 14,800, or nearly half, were employed by firms in Paper Mills (SIC 262). The second largest category in employment terms was Converted Paper (SIC 264), with over 20 percent of SIC 26 employment (Northwest Power Planning Council, 1982b). Most of the pulp and paper firms in the region are located in Oregon and Washington.

The Pacific Northwest pulp and paper industry supplied an average of 14 percent of national pulp production and an average of 10 percent of national paper and paperboard production in the 1970's (Data Resources, Inc., 1981). The region's share of pulp production was down from an average of 17 percent during the 1960's.

Pulp is produced from wood chips and other materials for subsequent manufacture into paper and paperboard products. Most of the pulp produced in the region is classified under paper mills and paperboard mills, since a number of the plants are vertically integrated.

Most of the raw material used in the pulp-making process is wood chips, by-products from lumber and plywood plants. Availability and cost of wood chips in the future operate as a constraint on capacity expansion in this region. Competition for portions of the timber resource has increased because of practices such as improvements in yield from each log by sawmills and plywood plants, and timber management practices which produce more uniform logs. Another factor has been the growth of the export market for chips during the 1970's.

As the cost of wood chips from lumber mills increases, pulp and paper mills will be required to purchase more timber for chips, adding to costs of production. The cost of wood chips also increases dramatically when they must be transported to the western portions of Oregon and Washington from east of the Cascades. The price of pine pulpwood in the South is less than half the price of roundwood in the Northwest (Northwest Pulp and Paper Association, 1982b).

As in the lumber industry, many of the companies are national in scope and decisions on capacity expansion are made with regard to regional differences in production costs. In 1983, approximately 63 percent of the industry's total capital expenditures will be directed toward mills and projects located in the South (Pulp and Paper, 1983). In addition, projections indicate that as much as 45 percent of new paper-producing capacity through 1984 will be built in the South (Northwest Pulp and Paper Association, 1982b).

For several years amidst the recession, the South has witnessed a major resurgence in planned capital spending for expansion and modernization projects in pulp and paper mills. Since 1980 this trend has been significant as figures show the South's share of national planned expansion and modernization funds to be greater than half of the nation's total: 63 percent for 1983; 60 percent for 1982; and 55 percent in 1980 (Pulp and Paper, 1983). Total spending for the South is reported in the Pulp and Paper 1983 survey to be \$5.2 billion. The West's share has been dropping in recent years, reflecting the long-run shift of new capacity additions to the South.

The Mountain/Pacific region's share of total production costs which are accounted for by energy costs is among the lowest in the nation. Table III-13 compares estimated energy costs relative to total costs among the eight pulp and paper regions. On a comparative percentage basis, energy capital expenditures are highest in the nation in the South Atlantic region with 47 percent during the period 1982-84. The

Mountain/Pacific figure of 24 percent is clearly below the National average of 31 percent. Therefore, pulp and paper production in the Mountain/Pacific region may not be as sensitive to energy costs as in other regions of the country.

Table III-13

Pulp and Paper Industry
Estimated Energy Share of Total Production Costs
By Region, 1982-1984

<u>Region</u>	<u>Percent</u>
New England	40
Mid-Atlantic	43
East North Central	20
West North Central	13
South Atlantic	47
East South Central	19
West South Central	35
Mountain/Pacific	24
National Average	31

Source: Developed from "Capital Spending," Pulp and Paper, January 1983, p.82.

(c) Chemicals and Allied Products

The manufacture of chemicals and allied products (SIC 28) consumed 14 percent of electricity purchased by the industrial sector in 1980 (Table III-1). Chemicals is the third largest industrial consumer of electricity in the region, following Primary Metals and Pulp and Paper.

In 1980, 13,750 persons were employed by Pacific Northwest firms in this industry, and 50 percent of these were employed by firms in Industrial Inorganic Chemicals (SIC 281). This category includes the industries within Chemicals that are the most electricity intensive: Chlorine and caustic soda (SIC 2812), elemental phosphorus (SIC 2819), and nuclear fuels and processing. Firms in SIC 281 consumed over 80 percent of the electricity purchased by the Pacific Northwest chemicals industry in 1977. Elemental phosphorus production accounted for half of the electricity consumed by the chemicals industry, followed by chlorine and caustic soda (15 to 20 percent) and nuclear fuels and processing (10 percent). Two of the chlorine and caustic soda plants and one elemental phosphorus plant are DSI's.

The manufacture of chlorine and caustic soda involves the electrolytic separation of salt into two co-products: chlorine and sodium as sodium hydroxide (caustic soda). Approximately 1.12 pounds of caustic soda are produced per pound of chlorine.

Chlorine and caustic soda is produced in five plants in the Pacific Northwest, with four located in Washington and one in Oregon. Nationally, over half of the chlorine produced is used within the chemicals industry in the manufacture of a variety of organic and inorganic chemicals. An additional 13 percent is used by the pulp and paper industry as a bleaching agent in the production of paper. Two of the five plants in the Pacific Northwest are owned by pulp and paper companies.

Elemental phosphorus production is located in only four states in the nation (Idaho, Florida, Montana, and Tennessee), in close proximity to deposits of phosphate rock. Elemental phosphorus is extracted from phosphate rock in electric furnaces, and frequently converted nearby to phosphoric acid and other compounds.

Elemental phosphorus plants are classified under Industrial Inorganic Chemicals, not elsewhere classified (SIC 2819). In the Pacific Northwest, firms producing elemental phosphorus, nuclear fuel, corn starch, chemical catalysts and a variety of other products are classified under SIC 2819. About half of total U.S. elemental phosphorus production capacity is located in the Pacific Northwest. Of this, 85 percent of capacity is located in Idaho, with the remainder in Montana.

The residual category for chemicals includes a wide variety of products manufactured in the Pacific Northwest. The larger groups in employment and energy use are the nuclear engineering, fuels and waste processing segment, and agricultural chemicals (primarily fertilizers and pesticides). There are also many other types of chemical products manufactured in the region produced to meet regional demand.

(d) Transportation Equipment

Transportation equipment (SIC 37) is the second largest employer in manufacturing in the Pacific Northwest. In 1980, 109,300 persons, which represented 19 percent of manufacturing jobs, were employed in transportation equipment. Transportation equipment includes the manufacture of aircraft, ships and boats, motor vehicles, railroad equipment, and travel trailers. Nearly three-fourths of the employment in transportation equipment in the region is in aerospace, which is dominated by the Boeing Company. Employment in SIC 37 has fluctuated in the region, reaching a peak of 128,900 employees in 1968, and a low of 64,400 in 1971. Aerospace employment in Washington was 79.6 thousand in 1980.

(e) Food and Kindred Products

Food and kindred products (SIC 20) is supported by a sizable agricultural industry in the region. In 1980, 73,150 persons were employed in SIC 20, which represented 12 percent of manufacturing jobs. Activity in this industry is concentrated in preserved fruits and vegetables (SIC 203), which accounted for nearly half of the employment in food and kindred products and over half of the electricity consumption. Processed potato products are the major products in this category, accounting for over half of the value added in the regional food processing industry. Another

portion of the industry important to coastal areas is the seafood canning and freezing industry. Recent poor commercial fishing conditions, however, have closed a number of these plants.

(f) Electronics

The electronics industry has been the fastest growing manufacturing industry in the nation and the Pacific Northwest. The industry includes Professional Instruments (SIC 38), Electrical machinery (SIC 36), and Computing Equipment (SIC 3573-4). All of machinery (SIC 35) is included in this analysis. Employment in electronics has quadrupled in the region since 1960, although it increased by only 59 percent in the nation.

(3) Role in the Pacific Northwest Power System

The large industrial customers of retail utilities provide a major role in the Pacific Northwest power system, not only because of their high volume of electricity consumption, but also because of the nature of their operations. These industries tend to consume electricity in continuous, uniform amounts, resulting in high load factors. To the extent that they maintain high annual load factors, they provide some of the same benefits of efficiency to the regional system as do the DSI's (see Chapter IV.D.2.b). In addition, some of the industrial customers, particularly in the wood products industries, have developed cogeneration capabilities, thereby providing an additional source of power to the region (Section IV.H.2). Some industries having alternate fuel capability can provide additional nonfirm energy markets (Section II.C.3.d.).

d. Irrigated Agriculture

As a result of BPA's rate increase, it is probable that most irrigators will attempt to run their operations more efficiently. Some "marginal" farmers may find it uneconomical to continue their operations and would therefore sell their property. These displaced farmers would have to seek employment elsewhere, either working for another farmer or getting an entirely different type of job.

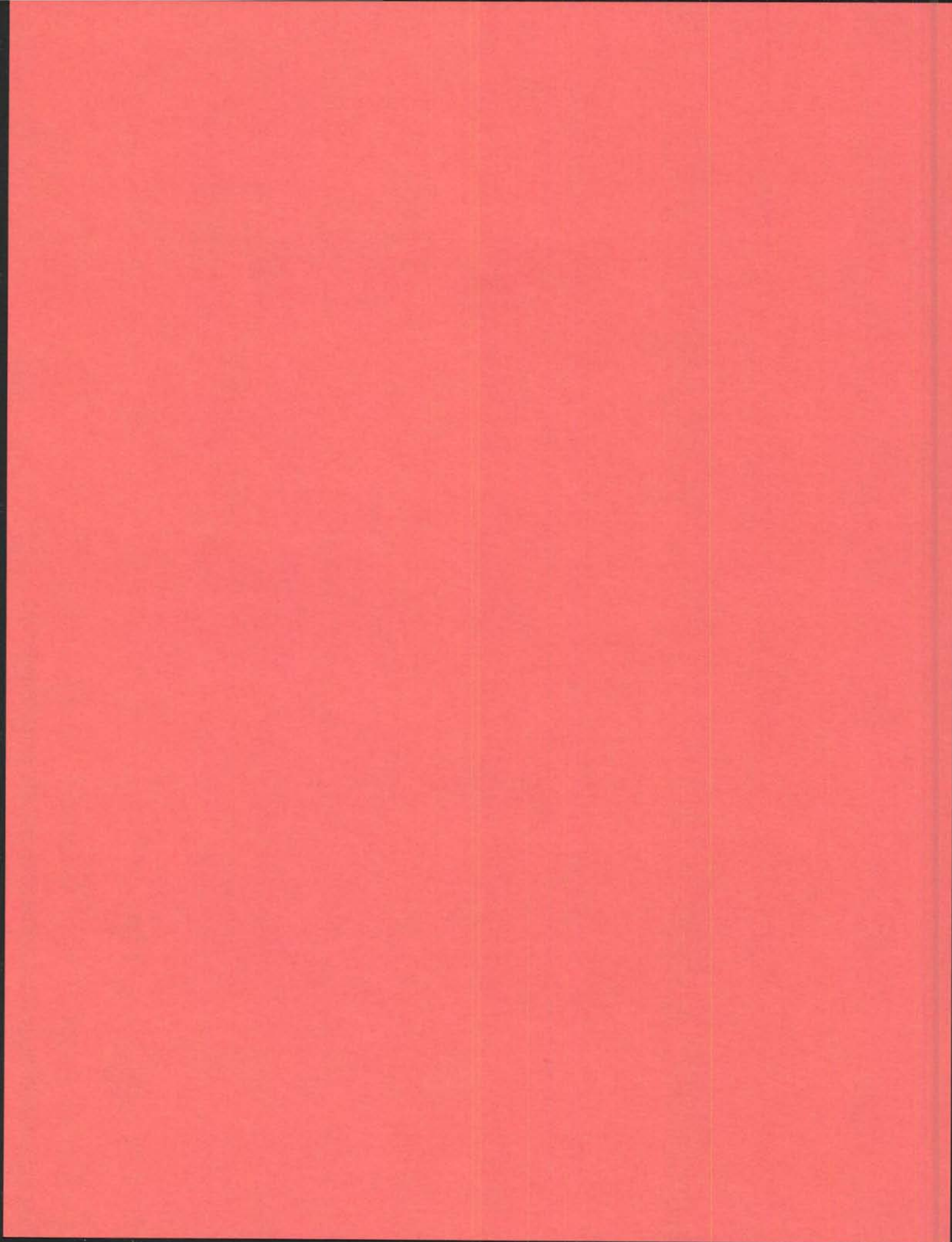
Though total irrigated cropland is projected to increase under all revenue level alternatives, some areas are more vulnerable than others to rising electricity prices. These areas share common characteristics of sandy soils, low rainfall, and high pump lifts. These areas include selected locations in Southern Idaho, the Columbia Basin in Washington, and the Columbia Bench in Oregon.

FOOTNOTES

- 1/ Salmonoids include chinook, coho, pink, sockeye, and chum salmon; steelhead and cutthroat trout; and Dolly Vardin char. Nonsalmonoids include American shad, sturgeon, striped bass, eulachon (smelt) and Pacific lamprey.
- 2/ Includes the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.
- 3/ Assumes 3540 MW of coal fired generation requiring an average of 9 tons per megawatt per day.
- 4/ Assumes 1990 MW of nuclear generation requiring an average of 40 tons of fuel per year for a 1250 MW light water reactor.

Chapter IV

Environmental Consequences



IV. Environmental Consequences

A. Introduction

This chapter examines the methods and techniques employed in evaluating the consequences of an increase in BPA's wholesale rates. Particular attention is paid to evaluating those impacts to the physical and socioeconomic environment which were addressed as areas of particular concern in Chapter III. These include irrigated agriculture, energy intensive industries, and low-income residential consumers.

A simulation and linear programming modeling process was employed to analyze the impact of an increase in revenue level on the regional demand for electricity. The results of this analysis formed a basis for projecting the effects of rate levels on energy consumption and various socioeconomic and physical aspects of the environment. These models will be described briefly in Section IV.B.

Northwest Economic Associates (NEA) has been commissioned by BPA to develop a model of Pacific Northwest agriculture. This model is adapted from NEA's linear programming model developed for the Northwest Agricultural Development Project. Results of this model will be included in the 1983 Final Rate EIS. A description of the model, and assumptions currently employed in a simulation of the model, is presented in Section IV.C.

Section IV.D. addresses BPA's direct service industries (DSI's). The DSI's accounted for 36 percent of BPA's total FY 1982 firm power sales. The DSI aluminum producers accounted for 92 percent of the FY 1982 kilowattnour sales to DSI's (BPA, 1983b) and are highly energy intensive. For this reason, the DSI aluminum producers are a focus of this section. BPA's effect on the DSI's, impacts of DSI plant operations, and the character of the national aluminum market are addressed in detail. A special modeling effort was undertaken to analyze the potential impact of various factors on DSI aluminum producers. A summary of the model's operation, and results obtained from the model, are presented.

Industrial customers of Pacific Northwest retail utilities constitute a large share of the region's total electric load. Section IV.E. presents an overview of the major industry groups, an analysis of the relationships of BPA's wholesale rates to the industrial customers of retail utilities and a discussion of potential responses by industry to decreased product demand or increased production costs.

In Section IV.F., the relationship between the Pacific Northwest and the Pacific Southwest with respect to interregional electric power transactions is addressed. The discussion focuses on the historical importance of BPA sales to California utilities, as well as California's future load and resource outlook and potential for future interregional electric power sales.

Section IV.G. presents background information on the historic response of residential consumers to increases in energy costs, particularly

electricity costs. The discussion focuses particularly on low-income residential consumers, who are found to be most impacted by increased electricity prices.

Electricity prices affect the demand for electricity and hence the need for generation resources. Section IV.H. of this chapter provides information on the environmental effects of various resource types that may be required to meet future loads. This information was used to develop the impact projections for generation facilities presented in Chapter II. For purposes of assessing the potential effects on the physical environment of changes in required generation, new generation requirements are assumed to be met by a combination of available resource types which include large thermal, hydro, cogeneration, geothermal, and conservation. The environmental effects of constructing and operating (or avoiding operation of) generation facilities (in response to changes in the demand for electricity resulting from changes in electricity price) then are evaluated, and, when possible, quantified.

Section IV.I. describes the functions of cost allocation and rate design as applied in the 1983 Initial Proposal. Issues with the individual allocation and design steps are identified and alternatives are analyzed. Finally, the section analyzes three rate structure alternatives (flat rates, declining block rates, and tiered rates).

The final sections of this chapter address specific topics of concern in NEPA: mitigating measures, unavoidable adverse impacts, short-term uses of environmental resources versus maintenance and enhancement of long-term productivity, and irreversible or irretrievable commitments of resources.

B. Discussion of BPA's Load and Resource Modeling Processes

A series of modeling steps was used to evaluate the impacts of each revenue level alternative. The Energy Simulation Model, consisting of supply and demand components, provides various types of forecast information including kilowatthour consumption and total dollar costs of energy. Forecast peak and average loads from the Energy Simulation Model are then input to a Load and Resource Balance Analysis, which determines annual resource surpluses or deficits based on projected availability of existing and planned (committed) resources to meet these loads for each year. The annual surplus and deficit projections reflect the need for additional resources beyond existing and planned generation, and are then input to the System Analysis Model (SAM) and the Least Cost Resource Mix Model. The Least Cost Resource Mix Model is a linear programming model which estimates the mix of resource types, which, if added to existing and planned resources for each year during the forecast period, results in the lowest new system investment in current dollars. The SAM is a simulation model of the economics and reliability of Pacific Northwest resource plans. SAM is an ongoing project that is being refined and improved.

BPA's Energy Simulation Model consists of two distinct elements; i.e., supply and demand. The model is a supply/demand model that iteratively generates load projections and prices. The supply/pricing portion of the model can project wholesale and retail rates based on the cost of resources, both Federal and non-Federal, needed to meet a set of loads determined outside the model. The retail public and private utility rates by

customer class (residential, commercial, and industrial) for each forecast year become inputs to the demand side of the model. The demand models use a matrix of prices to generate expected demand for electricity over the same forecast period. The new loads are then input back into the supply/pricing portion of the Energy Simulation Model to generate new energy prices. The new price matrix is then entered into the demand side to generate a new set of loads. This manual iteration between the demand and supply portions of the model continues until a convergence is reached whereby loads and prices arrive at a point of equilibrium. The forecast needs for unplanned resources for each year are then determined by the Load and Resource Balance Analysis and input to the SAM and the Least Cost Resource Mix Model to determine yearly additions of various resource types; e.g., large thermal, conservation, cogeneration and small hydro. The final solution is the expected loads and prices for each sector and the resulting resource mix for each year during the forecast period.

1. Energy Simulation Model

BPA's Energy Simulation Model simulates the Pacific Northwest's supply of and demand for electricity and provides a foundation for much of the analysis in this document. This model accommodates analyses of effects on loads and retail rates through FY 2000 of alternative wholesale energy price levels, future resource mixes, rate structures, and other factors.

The model projects the regional effects of changes in rates on electric consumption among residential, commercial, and industrial users. It also forecasts the conversions by consumers to other types of energy (fossil fuels) in response to price and availability of electric power. Given a mix of available current and future sources of electricity, the model develops a schedule for yearly additions of planned hydroelectric and thermal units, unplanned resources (such as cogeneration or small hydro) and conservation.

The current BPA supply model evolved from the model developed in 1977 for use in BPA's Role EIS (BPA, 1977a; BPA 1980a). The model has been modified on an ongoing basis to represent new developments in areas such as policy decisions, the Regional Act, availability of resources, and planning assumptions. The demand side of the model was developed from the Oak Ridge National Laboratories (ORNL) residential and commercial models, and the Northwest Energy Policy Project (NEPP) industrial demand models (BPA, 1981k; BPA 1981j, and BPA 1981m). An overview of the Energy Simulation Model, the types of output generated, and the assumptions made for the analysis is presented in the sections which follow. Detailed discussions of the supply and demand portions of the BPA Energy Simulation Model have also been developed in separate documents (BPA, 1982h; BPA 1983e). These technical support papers are available from BPA on request.

a. Supply Pricing Model

(1) Inputs

The amount of load that must be met by the Supply Pricing Model is determined by a combination of (1) direct inputs of load data and (2) load data generated by the demand models. The direct inputs include fixed contractual loads, exports, and Federal agency loads for each year in

the forecast period. The demand models provide estimates of residential, commercial, and industrial loads served by both public and private utilities. DSI loads are provided by a separate BPA forecast (see also Section IV.D.4.).

The model uses existing and planned resources and resources specified by the Least Cost Resource Mix Model to meet defined load requirements. The composite generating capacity of all regional hydro units under average and critical water conditions is specified. A simulation of historic streamflows is utilized to estimate the secondary energy from the hydro system and to allocate it on a priority basis across potential markets. Other resources available to the model include existing and future thermal facilities, capacity/energy exchange agreements, contracted energy from the Canadian Storage Power Exchange (CSPE), purchase power and cogeneration. The Supply Pricing Model includes investment, operating, and contract costs of the various energy resources. Costs of currently budgeted FY 1983 and FY 1984 BPA conservation programs are input to the model. Conservation expected to result from these programs is input to the demand side of the model. BPA transmission costs were input based on recent analysis by BPA staff. Public and private utility transmission costs and costs of distribution to customer groups were derived from annual financial statements and information provided by utility staff.

(2) Operation

The Supply Pricing Model first allocates existing resources to meet BPA's load requirements in a given year. After making proper adjustments for various contractual arrangements which provide resources to the utilities, the model checks the resource/load balance for public and private utilities. Any deficits for either the public or private sectors are assumed to be met by addition of future available resources (including conservation and cogeneration), purchases from BPA, and purchase power.

The determination of energy costs begins with a calculation of all capital, operating and contract costs for all resources used to meet the load requirement. The energy costs are adjusted for revenues from secondary hydro energy. The model also ensures that the resource pools are matched to the load pools to determine BPA's nontransmission cost of providing energy to the different load pools. This calculation for each year is treated in a manner that is consistent with the Regional Act. The Regional Act also provides for a value of reserves credit to DSI customers and the residential and small farm load exchange between BPA and participating utilities. Federal transmission costs are then added to determine BPA's rates.

The Supply Pricing Model then estimates retail rates of private and public utilities based on their wholesale cost of power from BPA as calculated above (or as determined outside of the model), utility generation and transmission costs, the private residential exchange, and utility costs of distributing power to residential, commercial, and industrial customers.

(3) Results

The Supply Pricing Model generates forecast data for each year in the forecast period by customer class, resource type (hydro, thermal, purchase power, etc.), and energy class (firm or secondary). These data include price per kilowatthour, total dollar cost, and total kilowatthours of energy generation. The model accommodates analyses such as breakdowns of costs between generation and transmission, comparisons of critical and secondary resources to firm and secondary loads, and forecasts of resource mixes necessary to meet aggregate loads.

b. Demand Model

Demand, as used in the context of this discussion, refers to the term in standard economic reference and not in the context in which the term is used in the electrical energy industry. The demand portion of the model simulates changes in the quantity of electricity consumed in response to changes in the price of electricity, the price of alternate fuels, ownership and use of appliances, housing, population, and income characteristics.

The change in the amount of electricity consumed resulting from a change in price is a function of the elasticity relationships that the model simulates. Price elasticity of demand is measured by the percentage change in quantity demanded of a good or service divided by the percentage change in price. For example, if electric rates increase by 30 percent but the quantity of electricity demanded decreases by only 5 percent, then price elasticity is said to have a relatively inelastic value of $-.17$. In this example, quantity demanded is relatively unresponsive to a price increase. Cross elasticity of demand measures the effect of changes in the price of substitute fuels (oil, gas, etc.) on the quantity of electricity consumed. Income elasticity reflects the impact of income changes on electrical consumption.

The demand side of the model uses three previously developed models (the Oak Ridge National Laboratory residential and commercial models and the Northwest Energy Policy Project industrial model) and direct input information on BPA conservation programs and DSI expected operating demands.

(1) Inputs

The residential model contains information on energy use for eight end-use categories (space heating, air conditioning, water heating, cooking, refrigeration, freezing, lighting, and other) for the 1979 base year. This information is input for four fuel categories (electricity, natural gas, fuel oil, and other) and for three housing types (single family, multiple family, and mobile homes). Base year values also include behavioral variables used in economic relationships and parameter estimates of technical relationships (e.g., appliance efficiency). In addition, projected housing stocks, fuel prices, and per capita income are input for each year during the forecast period. Cumulative amounts of conservation resulting from BPA budgeted FY 1983 and 1984 conservation programs are also input over the forecast period.

The commercial model inputs are also a combination of base year data and forecast data to the year 2000. Data on floorspace in 1924 and yearly additions to floorspace through 1980 for 10 building types are input. Base year data for 1970 on end use by fuel type, energy use per square foot, fuel prices, and capital costs of heating, ventilating and air-conditioning equipment are included, along with historic and forecast data for fuel prices and real per capita disposable income. As in the residential model, anticipated savings from the currently budgeted FY 1983 and FY 1984 BPA conservation programs are reflected over the forecast period.

Forecasts from the industrial model are based on historic and projected energy prices, employment, value added, and personal income. BPA's DSI customer demands for energy during the forecast period constitute a separate input.

(2) Operation

The residential demand model uses measures of short-run and long-run responses to specified prices of alternate fuels, technical trends (e.g., appliance efficiency), housing characteristics, and income data. This information, in conjunction with prices for electricity obtained from the Supply Pricing Model, determine yearly electrical demands. An adjustment is made to reflect the effects of BPA programmatic conservation, while price induced conservation is considered to be part of any decrease in electric consumption in response to price.

The commercial model projects four influences of building fuel use: floorspace (by building type and vintage), floorspace saturations (by fuel type and end use), equipment utilization, and energy use per square foot. These projections for each year are multiplied together to forecast commercial energy use, using specified projections for nonelectrical energy prices and electricity prices input from the Supply Pricing Model. Appropriate allowances are made for BPA conservation programs.

The demand for energy within the industrial sector is forecast using data for projected electrical demand among DSI customers and the NEPP industrial model. The NEPP econometric model estimates, for a given year, total energy demand among non-DSI customers based on estimates of energy prices (electricity prices obtained from the Supply Pricing Model), employment, value added, and personal income, and the previous year's demand. The model then distributes the total demand for energy among fuel types, taking into account limitations in fuel switching as a result of existing stocks of capital goods. The projected consumption of electricity among DSI customers is based on a simulation model of DSI loads developed by BPA staff (see Section IV.D.4.a.).

(3) Results

The residential demand model produces forecasts for energy use by fuel type, by type of dwelling, and by end use. Forecasts for energy consumption in the commercial sector are by fuel type, building type, and end use. The industrial model provides forecast energy demand by fuel type.

2. Load and Resource Balance Analysis

The annual energy and peakloads forecast by BPA's Energy Simulation Model is input to the Load/Resource Balance Analysis to determine surpluses or deficits for each year in the forecast period. The methodology for this analysis is in accordance with modeling used to complete the Pacific Northwest Utilities Conference Committee (PNUCC) report Long Range Projection of Power Loads and Resource for Resource Planning (Bluebook) (PNUCC, 1982).

The array of resources available to meet loads is a combination of existing and planned (committed) hydro, thermal and miscellaneous resources, both Federal and non-Federal. BPA programmatic conservation is not included as a resource, since appropriate adjustments for capacity and energy savings from these programs are made to the load forecast. The Load/Resource Balance Analysis incorporates critical water period planning assumptions (availability of hydro generation during low water periods) in determining availability and use of resources in meeting loads. These assumptions include provisions associated with the Water Budget for aiding in the downstream migration of fish. Adjustments for peak reserves of various resource types are also made.

In the load/resource balance, Federal and non-Federal resources are recognized to have certain priority load obligations. Loads on the Federal system include BPA's direct service industry customers and Federal agency loads. BPA also has a number of contractual obligations which include Columbia Storage Power Exchange (CSPE), WNP No. 1 exchange and Hanford extension obligations, capacity sales, and capacity/energy exchange. Sales to Northwest utilities under the power sales contracts constitute a major load to Federal resources. This load is calculated by analyzing the load/resource balance for each public utility in the region. The IOU's projected load growth requirements for Federal power are based on their contract exhibits. These load growth requirements are included as a load on the Federal system.

Non-Federal resources include power provided to the region by various contracts and agreements (e.g., CSPE) and generation resources owned by regional utilities. The power sales contracts require BPA's utility customers to serve their own loads with those resources they have dedicated for that use. Resources are characterized into dedicated or nondedicated resources for each customer. These dedicated resources must then be used by each customer to serve their loads and to determine their requirements for purchases from BPA. Customers may add or subtract from their exhibit of dedicated resources in the seventh year of the contract period (generally 20 years) and the power sale contract allows for quicker changes in certain circumstances. After the amount of dedicated resources are determined for each public utility, the net requirement on BPA (or BPA sales to the utility) is calculated. The net requirement load is the difference between each utility's load and the dedicated resources of that utility. The purchase from BPA is considered to be a load on BPA. The firm surplus of each utility is the amount of nondedicated resource of each utility.

The Federal system firm surplus or deficit for each year in the forecast period is determined after the requirements for the customers and

other contractual obligations are subtracted from the Federal resources. Any deficits that occur are loads that must be met from potential new (currently uncommitted or generic) resources (after exchange resources are used).

For a more detailed explanation of the load/resource balance methodology, the reader is referred to the discussion in the Loads and Resources Study (Exhibit BPA-3) for BPA's 1983 Initial Rate Proposal (BPA, 1983d).

3. Least Cost Resource Mix Model and System Analysis Model

The Least Cost Resource Mix Model is a linear programming model designed to estimate the "least cost" approach to meeting loads for each year during the forecast period. The SAM simulates the economics and reliability of actual and planned Pacific Northwest generating resources. Because SAM is an ongoing project that is still being refined, it is used in conjunction with the Least Cost Resource Mix Model. The models account for items such as cost and availability of potential resources, periods of projected surpluses and deficits for both energy and capacity, the value of surplus energy, ramping effects of conservation programs, and discount rates.

The SAM improves on the Least Cost Resource Mix Model by reflecting seasonal characteristics of loads and resources and by providing for the selection of certain resources on a temporary basis.

A detailed explanation of the Least Cost Resources Mix Model is provided in a technical support paper included in the Documentation for this EIS.

a. Inputs

The model contains availability and cost data on potential new resources. These resources include nuclear, coal, combustion turbines, small hydro, cogeneration, wind, and biomass. The model also accounts for the energy savings from conservation programs, savings which are cumulative and increase over time. For instance, a program directed toward wrapping water heaters can span a period of several years, resulting in increased savings in electric consumption as more water heaters are wrapped. Therefore, as an energy resource, conservation benefits differ from generating resources whose total capacity to meet electric loads is more closely identified with an on-line date, or beginning date of operation. Parameters for these ramping effects of conservation are specified in the model. Forecast surpluses or deficits for each year, for both capacity and energy, are specified based on information obtained from the Energy Simulation Model.

The Least Cost Resource Mix Model is capable of accomplishing various types of sensitivity analysis, based on changes in assumptions of any of the above inputs, the discount rate, or other variables. For the purposes of this statement, the model was employed to project resource mixes for resources beyond existing and currently planned resources for forecast loads generated by the Energy Simulation Model under four pricing scenarios.

b. Operation

The model uses the linear programming approach to minimize the present value of costs of balancing loads and resources for each projected deficit year, in view of specified constraints for cost and availability of resources. The model may add resources during surplus years if, in fact, addition of those resources is necessary to simultaneously meet loads in a later deficit period and still minimize costs. During surplus years, a marginal value of energy is estimated based on export sales, displacement of variable costs of other resources in the Region, and displacement of short-term purchases to meet firm load. This marginal value of energy is used to estimate revenue from surplus energy sales. This surplus revenue constitutes an offset to costs, and has a decreasing effect on the net present value of costs of meeting loads for the entire forecast period.

c. Results

The Least Cost Resource Mix Model presents a summary of present values of generating resource costs, conservation costs, and revenues for the entire forecast period. The solution provided by the model includes a listing of resource additions (in megawatts of capacity and megawatts of energy) by year and resource type. The future environmental impacts of these resource additions under alternative revenue levels are evaluated using information in Tables IV-15, 16, and 17.

4. Alternative Pricing Analyses

The BPA energy models were used to analyze four alternatives for presentation in the EIS. The purpose of the analysis was to compare the relative impacts of alternate wholesale electric prices during the period FY 1980 to FY 2000. Because electricity prices in each of the alternatives are determined outside the Supply Pricing Model to reflect alternative pricing assumptions, the function of the Supply Pricing Model to generate prices which achieve an economic load/resource equilibrium is superceded. The function of the Supply Pricing Model, for the purpose of analyzing these alternatives, was altered to provide the load levels that result from the assumed wholesale price alternatives. The results of these analyses reflect alternate total generation and resource mixes, which correspond with each alternative.

The base rate alternative assumes that the 1974 BPA wholesale rates were in effect throughout the entire FY 1980 to FY 2000 period. Average rates of 3.7 mills per kilowatthour for the Priority Firm rate (rates to public agency customers and the private utility residential and small farm exchange customers) and 2.9 mills per kilowatthour for BPA's DSI customers were input for the period, based on Generation and Sales Statistics for FY 1979 (BPA, 1980b) (the last full 12-month period) in which BPA's 1974 rates were in effect.

The no action alternative assumes the New Resources rate of 31.3 mills per kilowatthour for FY 1981 and FY 1982, and 29.5 mills per kilowatthour for the remainder of the forecast period. Generation and Sales Statistics data for FY 1980, FY 1981, and FY 1982 were used to determine average Priority Firm rates and DSI rates for those years. BPA estimates of average rates for FY 1983 were input for the period FY 1983 through FY 2000.

Based on those sources, the Priority Firm rates for FY 1980, FY 1981, FY 1982 and the period FY 1983 through FY 2000 were 6.4 mills per kilowatthour, 7.8 mills per kilowatthour, 11.4 mills per kilowatthour, and 18.0 mills per kilowatthour, respectively. The input DSI rates for FY 1980, FY 1981, FY 1982 and the period FY 1983 through FY 2000 were 4.6 mills per kilowatthour, 6.1 mills per kilowatthour, 16.1 mills per kilowatthour, and 24.5 mills per kilowatthour, respectively.

The proposed alternative assumes the same rates as the no action alternative through October 31, 1983, the date after which BPA's new wholesale rates are scheduled to go into effect. BPA's proposed rates for the period November 1, 1983, through June 30, 1984, of 22.0 mills per kilowatthour for Priority Firm, 24.8 mills per kilowatthour for Industrial Firm, and 28.8 mills per kilowatthour for New Resources firm power are assumed for that 8-month period. BPA's proposed July 1, 1984, wholesale rates are then assumed to be in effect for the remainder of the forecast period; i.e., through 2000. These rates are 22.8 mills per kilowatthour for Priority Firm, 25.7 mills per kilowatthour for Industrial Firm, and 29.9 mills per kilowatthour for New Resources Firm power.

For the direct financing alternative, rates are assumed to be identical to those rates which were assumed for the proposed alternative, with the exception of Priority Firm rate. For the period November 1, 1983, through June 30, 1984, the Priority Firm rate under direct financing assumptions is 25.8 mills per kilowatthour. The Priority Firm rate increases to 26.6 mills per kilowatthour for the period July 1, 1984, through FY 2000.

For the LRIC alternative, the same series of rates as the no action alternative are also assumed to be in effect through October 31, 1983. From November 1, 1983, through the end of the forecast period, a rate of 42.62 mills per kilowatthour (based on combined LRIC of energy and capacity as developed in BPA's 1983 TDLRIC Analysis; BPA, 1983f) are input for Priority Firm, Industrial Firm and New Resources customers.

C. Irrigated Agriculture Study

1. Introduction

Agriculture is one of the largest industries in the Pacific Northwest. In 1978, the value of farm products sold in Washington, Oregon, Idaho, and Western Montana totaled over \$5.1 billion (U.S. Department of Commerce, 1981b). Crop sales accounted for 55 percent of this total, and 45 percent was from sales of poultry, livestock, and related products. Farm output supports a very large food processing industry which supplies regional and national food needs. In addition, the Pacific Northwest is a major exporter of food commodities. The Port of Portland is the number one port on the West Coast in terms of grain exports (as well as being the West Coast leader in the tonnage of all goods exported).

The amount of productive cropland in the Pacific Northwest has not changed significantly in the last 30 years. The methods used to farm this land have, however, changed considerably. One of these changes has been a pronounced increase in the amount of cropland using irrigation methods. Improvements in irrigation technology have expanded the potential for

profitable cropping patterns. Sprinkler irrigation systems have helped to achieve high yield production on lands that otherwise could not be farmed profitably.

The importance of irrigation to crop production is suggested by results of a study in California. This study found that for nine crops grown intensively in that state, the use of irrigation water was the most important factor affecting crop production. The study estimated that a 50 percent reduction in the application of irrigation water resulted in a 49 percent reduction in crop yield for the nine crops studied (Battelle, 1977).

Irrigation methods fall into two broad categories: gravity (or flood) systems and sprinkler systems. Gravity systems transport water in open ditches or through low pressure pipes. The water is then distributed by flooding rows or the complete field.

Sprinkler irrigation systems distribute water over the field via pressurized sprinklers. There are seven basic types of sprinklers which range in operating pressure from over 100 psi for big guns and some center pivot systems to less than 10 psi for drip systems. These systems vary by (1) the amount of labor required to set up and operate the system; (2) the efficiency with which the water is applied; (3) geographic constraints to operation, (4) initial investment; (5) maintenance; and (6) power requirements to pressurize the water.

Irrigation water is obtained from groundwater wells, streams with gravity diversion canals, or water pumped from its source to point of use. Pumping may also occur where water in a gravity diversion must be lifted to a higher elevation.

Irrigation accounts for approximately 95 percent of all water consumed east of the Cascades and 30 percent of water consumed west of the Cascades (Washington Energy Research Center, 1977).

The region served by the Columbia River system faces several competing uses for water. One of these is the trade-off between agricultural uses of water and electricity generation capability. Withdrawals at the farthest upstream dams, Grand Coulee and Palisades, show the greatest potential electricity loss per acre foot diverted. John Day, a dam farther downstream, showed a potential hydroelectric loss only one-fourth as large. Estimated energy losses range from 30 kWh per acre foot at Bonneville to over 1500 kWh per acre foot at Palisades (Pacific Northwest Regional Commission, 1977).

In 1950, about 25 percent of the region's irrigated cropland was sprinkler irrigated. By 1980, this figure had grown to nearly 40 percent. The primary advantages of sprinkler irrigation over gravity irrigation are that water use per acre is much lower, and the uniform and consistent application of water allows more profitable cropping patterns on some land and production on other land that otherwise could not be farmed profitably. Also, increased use of sprinkler irrigation methods is due in part to the invention of high lift pumps, labor saving equipment, and new uses for irrigation sprinklers.

Since sprinkler irrigation may require large amounts of power, the availability of inexpensive electricity has also encouraged development of sprinkler irrigation.

Increased irrigation in the Pacific Northwest has led to a pronounced increase in irrigation energy requirements. Electricity used for irrigation pumping represents nearly 5 percent of total regional electricity loads.

The cost of electricity for irrigation pumping represents a significant variable cost to many producers. This cost typically is 5 to 10 percent of total production costs, depending upon crops and water lift.

In the Pacific Northwest, almost all of the energy used for irrigation pumping is electricity. Initial investment costs are lower for electric pumps than for diesel or gas, and electric pumps have a longer serviceable life. Electric motors are more readily changed or increased by a booster unit. Further, electricity supply is felt to be more dependable than the alternatives (natural gas, propane, diesel). A recent study (DOE, 1983) supports the expectation that electricity will continue as the predominant choice in the region. In 1981 dollars, alternate power sources were between 37 and 125 percent more expensive than the estimated LRIC retail price of electricity.

Early sprinkler irrigation systems took the form first of hand-moved pipes and then wheel-moved pipes. Recent sprinkler irrigation expansion has accelerated with the installation of center pivot circles. Most of these units have been installed in semi-arid areas previously classified as nonirrigable due to their sandy soil and undulated terrain. Water is pumped from underground sources and rivers or canals. This irrigation growth has taken place largely because of the labor and water savings possible in sprinkler irrigation systems, and the growing national and international markets for farm crops.

High crop prices in the early 1970's were a strong incentive for farmers to upgrade their capital stock and adopt new irrigation technology. Many of the farmers that did upgrade or expand have in recent years been caught in a serious cost/price squeeze as real crop prices generally have declined.

Expenses incurred by farmers for commodities and services, interest, taxes, and wage rates increased 9 percent nationally from 1980 to 1981. This compares to a 17.4 percent decrease in U.S. prices for potatoes, and 7 percent increase for U.S. wheat prices over the same period. Overall, the ratio (1977=100) of the index of prices received to costs (interest, taxes, and wage rates) was 85 in 1982 (USDA, 1983). That is, income received relative to costs for a "typical" farmer fell 15 percent between 1977 and 1982. Costs experienced by U.S. farmers increased 4 percent in 1982, compared to nearly a 9 percent increase in the previous year.

The combination of increasing costs and declining prices has caused financial problems for farmers, especially in the form of a heavy strain on cash flow. With the added problem of high interest rates, the financing of production inputs and capital goods is extremely difficult.

2. Modeled Response to BPA Revenue Level Alternatives

Projected impacts presented in Section II.B.3.f. are based on results of a linear programming model developed for BPA by Northwest Economic Associates (NEA). NEA adapted this model from a linear programming model developed by NEA for the Northwest Agricultural Development Project (NADP). NADP projections have been widely publicized and discussed throughout the region.

A linear program is a mathematical tool in which the value of a linear function is to be maximized or minimized subject to constraints (in the form of linear inequalities) imposed on a number of variables. Each of these variables may be constrained by physical, economic, technological, and agronomic considerations. Farm production, for example, is generally limited to land not developed for other uses (housing, roads), and that is not too steeply sloped. Thus, if the objective of this linear function is to maximize farm income, a constraint imposed on the land inventory variable would be that farm production may occur only on land available and suitable for farm production.

Another constraint might specify, based on agronomic and economic considerations, lower and upper bounds for the proportion of land that must lie fallow. Similar considerations specify bounds for cropping patterns. Farm production costs and product prices lead to specifications to the effect that production will not occur if income derived from the production is less than variable costs.

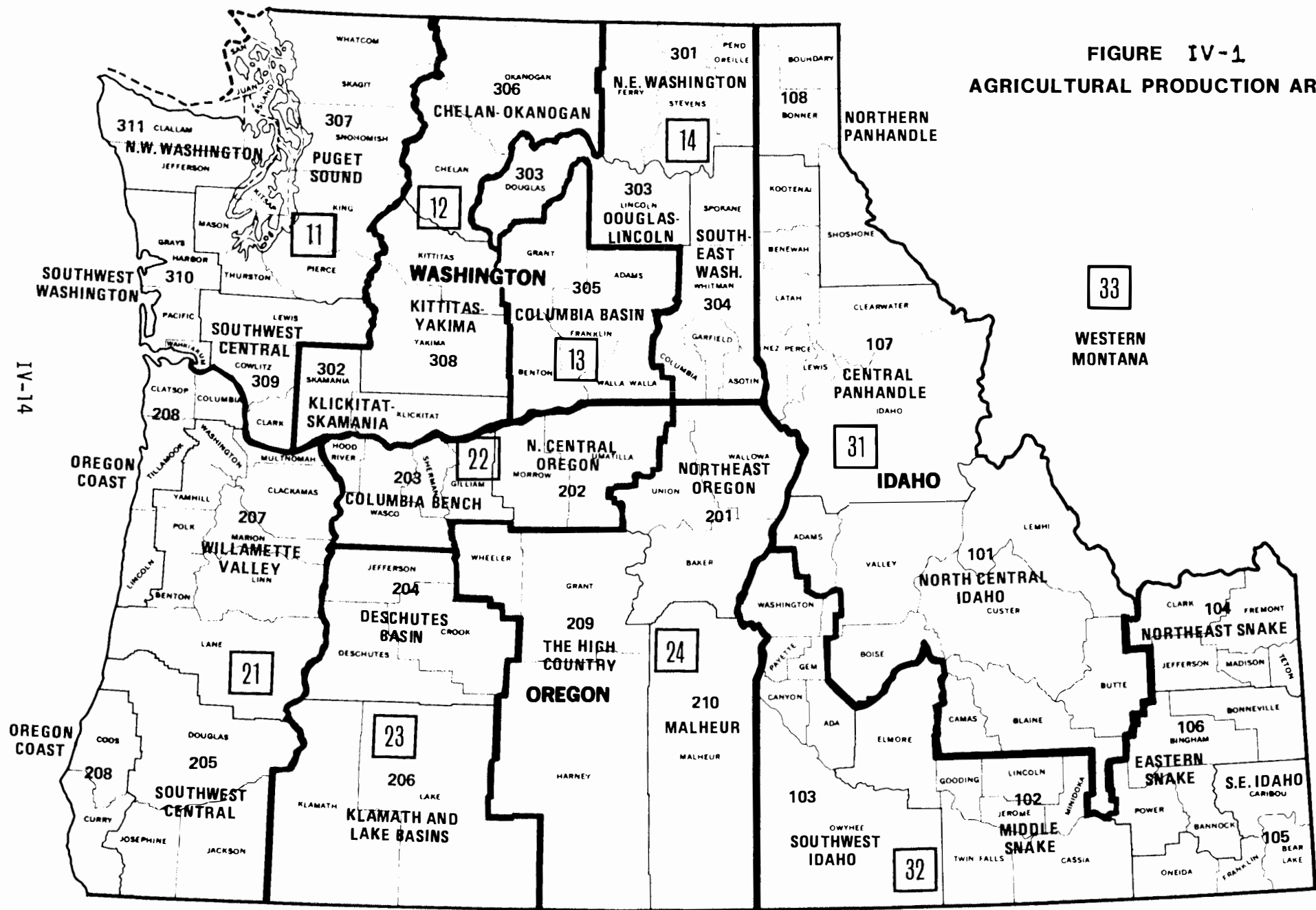
The constraints incorporated in BPA's model are based on historical data and projections of anticipated conditions. Projections specify, for example, the anticipated limits of efficiency gains in sprinkler irrigation technology.

Eleven production areas within the Pacific Northwest comprise the geographic units of analysis. These production areas are shown in Figure IV-1. Each production area has a unique set of constraints and conditions that influence projections of agricultural income and production. For this analysis, projections for the eleven production areas have been aggregated by state with Western Montana and Idaho combined.

The model's objective function is to maximize Pacific Northwest agricultural sector income. Variables that influence farm income, and accounted for in the model, include (but are not limited to) (1) land inventories (resource limitations); (2) labor and energy costs and other farm production costs; (3) adoption of improved irrigation management and technology; (4) marketing potential and export and domestic demand; (5) cropping patterns; and (6) food processing costs.

For this statement, the energy price variable was adjusted to reflect prices paid by irrigators in 1990 and 2000 under the four revenue level alternatives. Electricity price for each alternative was held constant (1980 dollars) while all other prices and costs were allowed to change over the forecast period. Thus, the price of electricity under each alternative declines over time relative to other variables. This approach may seem

IV-14



somewhat counterintuitive but is appropriate to the needs of this study. Effectively, this approach isolates results of each alternative forecast as due solely to electricity price differences.

Since BPA does not market directly to irrigators, each revenue level alternative is expressed as a retail electricity rate. The rates are derived from the Supply Pricing Model (see Chapter IV.B.1.a.) and reflect residential rates in constant 1980 dollars. These regional average rates were then modified to reflect actual retail rate differences between the eleven production areas. The alternatives are (1) Base Rate (17.8 mills per kilowatthour) with calendar year 1979 rates selected to reflect BPA wholesale rates in effect during 1974-79; (2) No Action (25.7 mills), regional average rates following implementation of BPA's October 1982 wholesale power rates; (3) Proposal (26.9 mills), average rates projected to result from BPA's November 1983 wholesale rate increase; and (4) LRIC (38.6 mills), projected November 1983 rates if wholesale rates are set at the long run incremental cost of power.

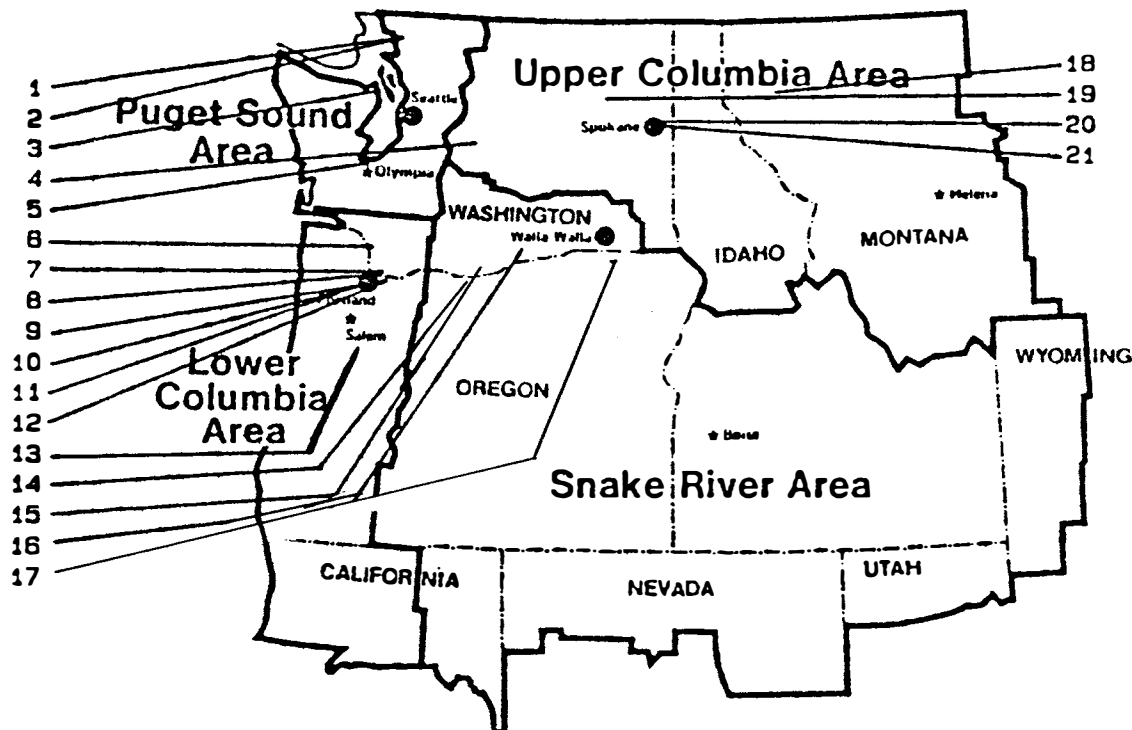
The model used budgets for each production area for farms potentially able to grow five different commodities. These commodities, representative of important regional cash crops, are wheat, apples, potatoes, alfalfa, and vegetables. The budgets were further differentiated by 5 lift zones and 3 irrigation types. Electricity required for pumping water in each lift zone was calculated for each irrigation system. It was assumed that no on-farm electricity is required to deliver surface water for gravity irrigation. Off-farm electricity costs were calculated for lands served by the Bureau of Reclamation. These were included as "other costs" in the farm budgets. Other variables incorporated in the model include: irrigation capital and annual costs, irrigation system efficiencies, adoption of improved irrigation technology, and better management.

D. Direct-Service Industrial Customer Study

1. Introduction

Within its service area, BPA has contracted to sell power directly to 15 direct-service industrial customers (DSI's) with a total of 21 plants. BPA's service to these industrial customers and the operation of their plants are closely related. Eight of the plants (including the proposed Alumax aluminum plant) are in Oregon, 12 are in Washington, and one is in Montana. Eleven of the plants produce and/or process primary aluminum, as would the proposed Alumax plant. Eight plants produce other electro-process products, and one plant produces pulp and paper. The primary aluminum plants accounted for 93 percent of BPA's direct industrial energy sales in FY 1982 and contributed approximately the same percentage of BPA's industrial revenues. Of the remaining industrial sales, the chemical industry is the next largest customer group with approximately 4 percent of BPA's industrial firm power. Figure IV-2 shows approximate location of each of the DSI plants.

FIGURE IV-2 LOCATION OF BPA DIRECT-SERVICE INDUSTRIAL CUSTOMERS



DIRECT-SERVICE INDUSTRIAL CUSTOMERS

1. INTALCO, Bellingham, WA	12. REYNOLDS, Troutdale OR
2. GEORGIA PACIFIC, Bellingham, WA	13. OREGON METALLURGICAL, Albany, OR
3. CROWN ZELLERBACH, Port Townsend, WA	14. MARTIN MARIETTA, The Dalles, OR
4. ALCOA, Wenatchee, WA	15. MARTIN MARIETTA, Goldendale, WA
5. KAISER, Tacoma, WA	16. ALUMAX (proposed) Umatilla, OR
8. REYNOLDS, Longview, WA	17. HANNA NICKEL, Riddle, OR
7. ALCOA, Vancouver, WA	18. ARCO METALS, Columbia Falls, MT
8. CARBORUNDUM, Vancouver, WA	19. ALCOA (N.W. ALLOYS), Addy, WA
9. PACIFIC CARBIDE, Portland, OR	20. KAISER, Mead, WA
10. ELKEM METALS, Portland, OR	21. KAISER, Trentwood, WA
11. PENNWALT, Portland, OR	

Table IV-1 lists each industry that has a member plant directly served by BPA and the representative percentage of the industry's national capacity. BPA's direct-service plants have the greatest production effect in the ferronickel, primary aluminum, titanium, silicon carbide, magnesium, and silicon industries where they account for between 11 percent and 100 percent of national capacity.

Table IV-1 is intended to show only the potential effect of the direct-service industrial customers on production capacity in their respective industries. It should not be interpreted as meaning that some of these industries could not supply enough output to meet demand without BPA's direct-service customers. It is apparent, though, that large scale future curtailment of the DSI's could significantly impact the national production capability of at least six industries.

TABLE IV-1
DSI SHARE OF NATIONAL CAPACITY

<u>Line No.</u>	<u>Industry</u>	<u>Percent Share of National Capacity</u>
1.	Ferronickel	100
2.	Primary Aluminum	33
3.	Titanium	21
4.	Silicon Carbide	20
5.	Magnesium	11
6.	Silicon	11
7.	Calcium Carbide	6
8.	Caustic Soda	1
9.	Chlorine	1
10.	Ferromanganese	1
11.	Ferrosilicon	1
12.	Siliconmanganese	1
13.	Pulp and Paper	1

Sources: Bonneville Power Administration, Draft Role EIS, Appendix C, 1977c.

The 10 existing aluminum reduction plants have a total product capacity of nearly 1.7 million short tons annually (Direct Service Industries, Inc., 1982), and represent approximately 33 percent of the United States primary aluminum smelting capacity. The proposed Alumax plant would add 220,000 short tons to this figure. Most of the nonaluminum products are industrial abrasives, ferroalloys, other primary metals, or products related to the paper industry. Hanna Nickel is the nation's sole producer of ferronickel, and Carborundum produces 20 percent of the nation's silicon carbide. Table IV-2 lists each direct-service industrial customer, the location of its Pacific Northwest plants, the products produced, and the major uses of those products.

TABLE IV-2

DSI LOCATION, PRODUCTS, AND PRODUCTS' MAJOR USES

Line No.	(a) Corporation	(b) Location	(c) Products	(d) Major Uses
	<u>Aluminum</u>			
1.	Alcoa	Vancouver, WA	Primary Aluminum, Rod, Wire & Extrusions	Construction, Transportation Equipment, Packaging, Electronic Components
2.	Alcoa	Wenatchee, WA	Primary Aluminum	
3.	Alumax ^{a/}	Umatilla, OR	Primary Aluminum	
4.	ARCO Metals	Columbia Falls, MT	Primary Aluminum	
5.	Intalco	Bellingham, WA	Primary Aluminum	
6.	Kaiser	Mead, WA	Primary Aluminum	
7.	Kaiser	Trentwood, WA	Aluminum Sheet & Fabricated Products	
8.	Kaiser	Tacoma, WA	Primary Aluminum and Rod	
9.	Martin Marietta	The Dalles, OR	Primary Aluminum	
10.	Martin Marietta	Goldendale, WA	Primary Aluminum	
11.	Reynolds	Longview, WA	Primary Aluminum, Rod, Wire, & Cable	
12.	Reynolds	Troutdale, OR	Primary Aluminum	
13.	<u>Other</u>			
14.	Alcoa	Addy, WA	Magnesium and Ferrosilicon	Construction, Alloying of Aluminum
15.	(N.W. Alloys)			
16.	Carborundum	Vancouver, WA	Silicon Carbide	Industrial Abrasive
17.	Crown Zellerbach	Port Townsend, WA	Pulp and Paper	Heavy Kraft Paper & Liner-Board
18.	Georgia-Pacific	Bellingham, WA	Chlorine, Caustic Soda	Bleaching of pulp & paper
19.	Hanna Nickel	Riddle, OR	Ferronickel	Stainless Steel
20.	Oremet	Albany, OR	Magnesium, Titanium	Aerospace Industry, paint, valves
21.	Pacific Carbide	Portland, OR	Calcium Carbide	Acetylene production
22.	Pennwalt	Portland, OR	Chlorine & Caustic Soda	Bleaching of pulp & paper
23.	Elkem Metals	Portland, OR	Ferromanganese, Calcium Carbide & Ferrosilicon	Alloying of steel, Acetylene production

^{a/} Proposed

Source: Data in table is based on direct-service industrial customers' responses to a questionnaire prepared by BPA in January 1976 and updated in August 1983.

As of February 1983, the industrial customers had a total contract demand of 3,711 average megawatts of industrial power. The Alumax contract would increase the industrial contract demand by 320 megawatts. As a group, the DSI's in the year ending September 30, 1982, accounted for approximately 26 percent of BPA's total energy sales and contributed about 34 percent of its annual revenues. (BPA, 1983c.)

The DSI study is presented in the following sequence. Section IV.D.2. examines the relationship between BPA and the DSI's. The characteristics of power BPA sells to its direct-service industrial customers differs from power sold to other customers in quality and conditions of use. There is also a unique relationship between service to the DSI's and BPA's operation of the Federal power system.

Section IV.D.3. explores the effects of rising industrial power costs. The focus of this section is on the aluminum producing customers, the most energy intensive industry in the region. Assessments are made of the aluminum industry in international and national markets. Comparisons between Pacific Northwest plants and other domestic and international aluminum producers are made with respect to power costs, operation rates, and investments in plant modernization.

Section IV.D.4. explains the modeling approach which was used to analyze the impact of BPA's revenue level on the level of aluminum production in the region.

2. BPA Industrial Firm Power

a. Characteristics of Industrial Firm Power

The terms under which industrial firm power is to be made available to the DSI's are defined in large part by the Regional Act. Service to the DSI's under the Regional Act is for power subject to restriction by BPA in order to serve other firm loads. To define the restriction rights and obligations of BPA and the DSI's, industrial firm power is divided into quartiles of service.

BPA plans and acquires sufficient resources to supply firm power to three quarters of the DSI load. The remaining one quarter, referred to as the "top quartile," is treated as a firm load for resource operating purposes but not for planning purposes. The top quartile is a quasi-firm load that does not require installation of additional resources to meet the load on an absolute firm basis.

The top quartile is served so as to supply the DSI's power with firm characteristics for the first 6 months of the critical period. This service is provided by firm DSI energy borrowed from the future and contractually secured through BPA restriction rights on other quartiles of DSI load. The balance of top quartile service is provided through nonfirm energy.

Borrowed energy can be achieved using a number of techniques. First, service may be provided through shifting the Federal system's firm energy load carrying capability (FELCC). FELCC shift is provided for under the Pacific Northwest Coordination Agreement of 1964 to

permit maximum flexibility in the use of the region's hydro and thermal resources. In general, this involves shaping reservoir draft (depth) from one year to another in anticipation of greater than critical level streamflows over a 4-year period. This may involve early release of water that, under critical water conditions, would be needed to serve future firm load. In practice, this means that reservoirs are drawn down to an earlier and deeper draft than otherwise would be prudent. If normal precipitation occurs and other resources operate as anticipated, the reservoirs will refill. If less than critical streamflows materialize and BPA is unable to meet firm obligations, BPA can restrict portions of the DSI's third quartile firm load in later periods to compensate for the borrowed FELCC.

A second method of serving the top quartile also involves advancing energy from a later period into an earlier period. As with shifting of FELCC, the success of advancing energy is dependent on streamflow conditions. Provision for payback of advanced energy is made if streamflows are not sufficiently above a critical level.

A third alternative for serving the top quartile is flexibility. Flexibility is the same as shifting FELCC, but is within 1 year rather than between years of the critical period. Flexibility can only be used within the constraints of the Coordination Agreement and must be paid back at a later time during the year, if streamflows don't materialize.

The other portion of the service to the top quartile is nonfirm energy. Nonfirm energy is the additional energy produced from actual streamflows over that produced under critical period streamflows. Nonfirm energy is offered to Northwest preference customers pursuant to P.L. 88-552 before it is used to serve DSI loads, pending the U.S. Supreme Court consideration of the Ninth Circuit Court decision in Central Lincoln I.

Industrial firm power supplied to the bottom three quartiles is of a lesser quality than firm power supplied to other users. When necessary to meet other firm power obligations, BPA may restrict DSI service under a number of conditions. These restriction rights provide a major part of the generation and transmission reserves needed by BPA. When necessary to meet its other firm power obligations, BPA can restrict DSI service as follows: (1) essentially the entire load for up to 15 minutes; (2) half of the load that is operating for up to 2 hours in any one day; (3) the second quartile if generating plant completions are delayed, generation or conservation investment resources don't perform as planned, or any operating plant experiences a forced outage; and (4) the third quartile if DSI's have borrowed on their firm energy as previously discussed, subsequent streamflows don't restore the reservoirs and the energy is needed by BPA to meet its firm obligations.

b. Relationship between Industrial Firm Power Sales and the Federal System

The DSI's comprise a unique customer class. This uniqueness stems from the type of demand they place on the generation and transmission systems, and the interruptible provisions of the power sales contracts.

DSI demand for electricity is characterized by a uniform and continuous use of electricity. This is in contrast to residential consumers' electricity demands, for example, which vary widely throughout the day, being highest during morning waking hours and early evening hours and then dropping off significantly during the late night and early morning hours. By using fixed amounts of electricity around the clock, the DSI's provide a market during times when other demands are typically low.

These DSI load characteristics permit BPA to sell large amounts of peaking energy during heavy load hours; the large night time loads enable BPA to accept return of peaking replacement energy while retaining sufficient load on the hydro system generators to meet minimum instream flow requirements. This also enables large thermal plants in the region to operate efficiently (around the clock operations) to return peaking replacement energy. Additional peaking and energy resources would be needed to serve equivalent load if BPA did not serve the large, constant DSI loads. It is more expensive and less efficient to generate power to serve highly fluctuating demands. The stabilizing effect of the DSI loads on the Federal system has benefitted all customers.

The benefits to the Federal system of a stable DSI load will diminish if regional aluminum plants increasingly become swing plants. This possibility is discussed in Section IV.D.3.a.(3). Swing plants usually are the first to curtail operations during periods of poor market conditions, and the last to resume operation when the market improves. Generally, market conditions that adversely impact aluminum producers indicate broader problems in the economy and reduced demand for electricity. Thus, DSI's operating as swing plants conceivably would exacerbate load fluctuations influenced by general economic conditions.

The interruptibility provisions of DSI power sales contracts (see Section IV.D.2.a.) further distinguish the DSI's from other customers. This interruptible capability enhances system reliability by providing reserves without adding generation. On other power systems, reserves are provided by building expensive standby power plants. By using the interruptibility provisions of the DSI contracts as a reserve of power, BPA has been able to keep the cost to all customers lower than if reserve generation had been added. These provisions do constitute a risk to the DSI's of short-run power deficits. The DSI's receive a credit in recognition of this risk as well as the value of the reserves which they provide to the region.

Top quartile combination service (borrowed energy and nonfirm energy) is also a benefit to the Federal system. Borrowed DSI firm energy effectively increases the limited storage of the FCRPS. The DSI's also have provided a market for nonfirm power, which can not be used to serve utility customer firm needs, resulting in a higher utilization of the FCRPS by serving more total electricity demand without building additional power plants. The result of top quartile combination service has been to expand FCRPS storage and spread operating costs over a market for nonfirm as well as firm energy.

Finally, in serving the DSI's, BPA is able to economize by using large transformers, fewer substations, and less transmission. This is

because the DSI's take power in large blocks, and from a single delivery point at or near each plant site. Further, most DSI's are located close to a source of generation, the main grid transmission system, or areas where the load is concentrated.

c. BPA Rates for Industrial Firm Power

The basis for the DSI rate was established by the Regional Act. The Act allows the residential and small farm consumers of IOU's to receive rate relief. The exchange provisions of the Regional Act allowed the IOU's to purchase relatively inexpensive Federal power from BPA and to sell an equal amount of power back to BPA at each IOU's average system cost. The amount of IOU load eligible for exchange was equivalent to 50 percent of their residential and small farm load beginning July 1, 1980, increasing 10 percent annually through July 1, 1985, after which the IOU's can exchange 100 percent of this load. Much of the additional cost to BPA resulting from the exchange is allocated to the DSI's. Consequently, the DSI rate is heavily dependent on the level of the IOU's average system cost.

The cost of BPA industrial power has increased significantly since 1979. The allocation of the costs of exchange resources, as directed by the Regional Act, has been a major factor in this increase. Under the rate in effect prior to December 20, 1974, industrial firm power, if purchased at 100 percent load factor, would have cost 2.0 mills per kilowatthour. This cost increased to 17.3 mills per kilowatthour during FY 1982 and is now estimated to be 24.5 mills per kilowatthour during FY 1983. The Regional Act has established that after June 30, 1985, the industrial power rate will be set at a level equitable in relation to the industrial power retail rates of public utilities within the region. This new rate is to be no less than the rate in effect for the contract year ending June 30, 1985.

3. Effects of Rising Costs on DSI Pacific Northwest Operations

BPA's direct-service industrial customers have paid less for electricity than most other Pacific Northwest industrial customers without access to Federal energy. BPA, therefore, has had the effect of lowering an industry's total production costs by providing its direct-service industrial customers with electricity at a lower cost than that paid by many non-DSI plants in the region.

A study by Ernst and Ernst (Ernst and Ernst, 1976) indicated that the electricity prices charged to the aluminum companies by BPA in 1975 resulted in net savings of 4.1¢ per pound of aluminum relative to other domestic aluminum producers. This savings in electricity costs offset the higher transportation costs paid by Pacific Northwest producers in shipping their product to the major market in the midwest. However, BPA rate increases since that time have reduced the previous price advantage.

This section focuses on the different aspects of current market conditions faced by the DSI customers, including trends in

costs of production and the current and projected demand for DSI products. Particular attention is given to the costs of electricity, which is a major cost component, especially for the aluminum industry.

a. DSI Aluminum Customers

Special emphasis is focused on BPA's 10 aluminum smelters BPA serves. In FY 1982, the aluminum companies paid 93 percent of BPA's industrial revenues (BPA, 1983b). The aluminum industry is the most energy intensive industry in the Pacific Northwest and is particularly sensitive to electricity price increases. This section assesses the aluminum industry from a national, international, and regional perspective and presents forecasts of industry response to BPA's revenue level alternatives.

(1) International Industry Assessment

Since 1980, U.S. aluminum producers have faced declining demand and falling prices for their products. These factors have led to a sharp reduction in domestic production and a declining share of world production. Many analysts forecast a continuing decline in U.S. share of world aluminum product (Tsai-Spector Research Associates, 1982a).

Table IV-3 presents the distribution of power rates by aluminum smelting capacity in the Western World. Most U.S. capacity operates at 21-30 mills per kilowatthour; most privately owned foreign capacity at less than 12 mills per kilowatthour; most government owned foreign capacity at less than 12 mills per kilowatthour.

Table IV-4 shows that at least 53 percent of the Western World aluminum smelting capacity operates at power rates which are lower than BPA's rate to the DSI's.

TABLE IV-3

DISTRIBUTION OF POWER RATES a/ BY ALUMINUM SMELTING CAPACITY
IN THE WESTERN WORLD
(000 Metric Tons)

	(a)	(b)		(d)	(e)
	Privately Owned	Govt. Owned (Local)			
Line No.	Power Rates Mills/kWh	U.S. Capacity	Foreign Capacity	Operating Rate (Percent)	Capacity Operating Rate (Percent)
1.	0 - 12	435	2,465	88 <u>b/</u>	1,954 88 <u>c/</u>
2.	13 - 20	763	694	86 <u>d/</u>	949 85 <u>e/</u>
3.	21 - 30	2,495	820	66 <u>—</u>	512 93 <u>—</u>
4.	31 - 40	949	409	60	100 40
5.	41 - 50	236 <u>f/</u>	—	21	— —
6.	Over 50	—	18	Unknown	— —
7.	Unknown <u>g/</u>	—	—	—	685 100
8.	Japan <u>h/</u>	—	390	38	— —
9.	TOTALS	4,878 <u>i/</u>	4,796	72	4,200 90
U.S. percent of Western World Capacity		<u>35</u>	<u>35</u>		<u>30</u>

a/ Rates in effect during October 1982

b/ Cutbacks: Alcan (Grande Baie) & Alcoa (Badin)

c/ Cutbacks: Venezuela, France, Norway

d/ Cutbacks: Wenatchee, Hannibal (19 mills)

e/ Cutbacks: West Germany, Italy (18 mills)

f/ Chalmette

g/ Yugoslavia, Egypt, Iran, Turkey

h/ Excludes Kambara (10 mills) and Miike (31 mills) which are included in their proper range. The rest of Japan is above 45 mills/kWh.

i/ Excludes San Patricio, Corpus Christi, Lake Charles

Source: Direct Service Industries, Inc., January 1983 (compiled by Alumax Pacific Corporation).

TABLE IV-4

DISTRIBUTION OF WESTERN WORLD ALUMINUM SMELTING
CAPACITY BY (OCTOBER 1982) RATE LEVELS

Line No.	Rate Level a/	(a)	(b)
		Metric Tons (000)	Percent of Total
1.	With Higher Rates than DSI's	2,100	15
2.	With Equal Rates	3,800	27
3.	With Lower Rates	7,300	53
4.	Unknown	690	5
		13,890	100

a/ Smelters with energy costs of 21-30 mills per kilowatthour were considered to have rates equal to BPA's rate to the DSI's.

Source: Direct Service Industries, Inc., January 1983 (compiled by Alumax Pacific Corporation).

The international industry assessment implies a potential exists for a shift of aluminum smelting capacity in favor of foreign production. Any relative increase in U.S. power costs will further reduce the U.S. competitive position.

(2) National Industry Assessment

The current national aluminum market is characterized by a slowed growth in domestic demand, excess inventories of primary aluminum, recessionary influences affecting primary aluminum consumption among key sectors of the economy, and the prospect of increasing imports from foreign producers. In the past, domestic aluminum consumption grew at a rate that greatly exceeded the rate of growth in the U.S. gross national product (GNP). However, as Table IV-5 indicates, the ratio of growth in aluminum consumption to growth in GNP has declined over the past three decades.

Table IV-5
GROWTH IN U.S. ALUMINUM CONSUMPTION AND GNP FOR SELECTED PERIODS

	A	B	C	D
		Average Annual Compound Growth Rates		
		Aluminum		Ratio of
<u>Line No.</u>	<u>Period</u>	<u>Consumption</u>	<u>GNP</u>	<u>Growth Rates</u>
		(percent)	(percent)	
1.	1951-1959	7.9	3.4	2.32:1
2.	1960-1969	7.5	4.1	1.83:1
3.	1970-1979	4.4	2.7	1.63:1

Source: Chris Kristensen and Joseph Correia, "The Pacific Northwest Aluminum Industry: The Impact of Anticipated Power Rate Increases to 1991," U.S. Department of Commerce, 1979.

The current trend in domestic aluminum consumption is affected by two factors: first, the national economy is growing less rapidly; and second, there are fewer new needs to be satisfied by aluminum. The building and construction industry and the transportation industry collectively accounted for 35 percent of domestic consumption in 1981 (see Figure IV-3). These industries have been among the hardest hit by the current recession.

Figure IV-3 shows the domestic markets which are the primary users of all aluminum products. In 1981, the container and packaging industry used over 26 percent of all domestically produced aluminum; the building and construction industry, 19 percent; the transportation industry, 16 percent; electrical industries, 10 percent. The remaining national aluminum production is used by industries producing consumer durables, machinery and equipment, and other items. Exports account for more than 10 percent of aluminum production.

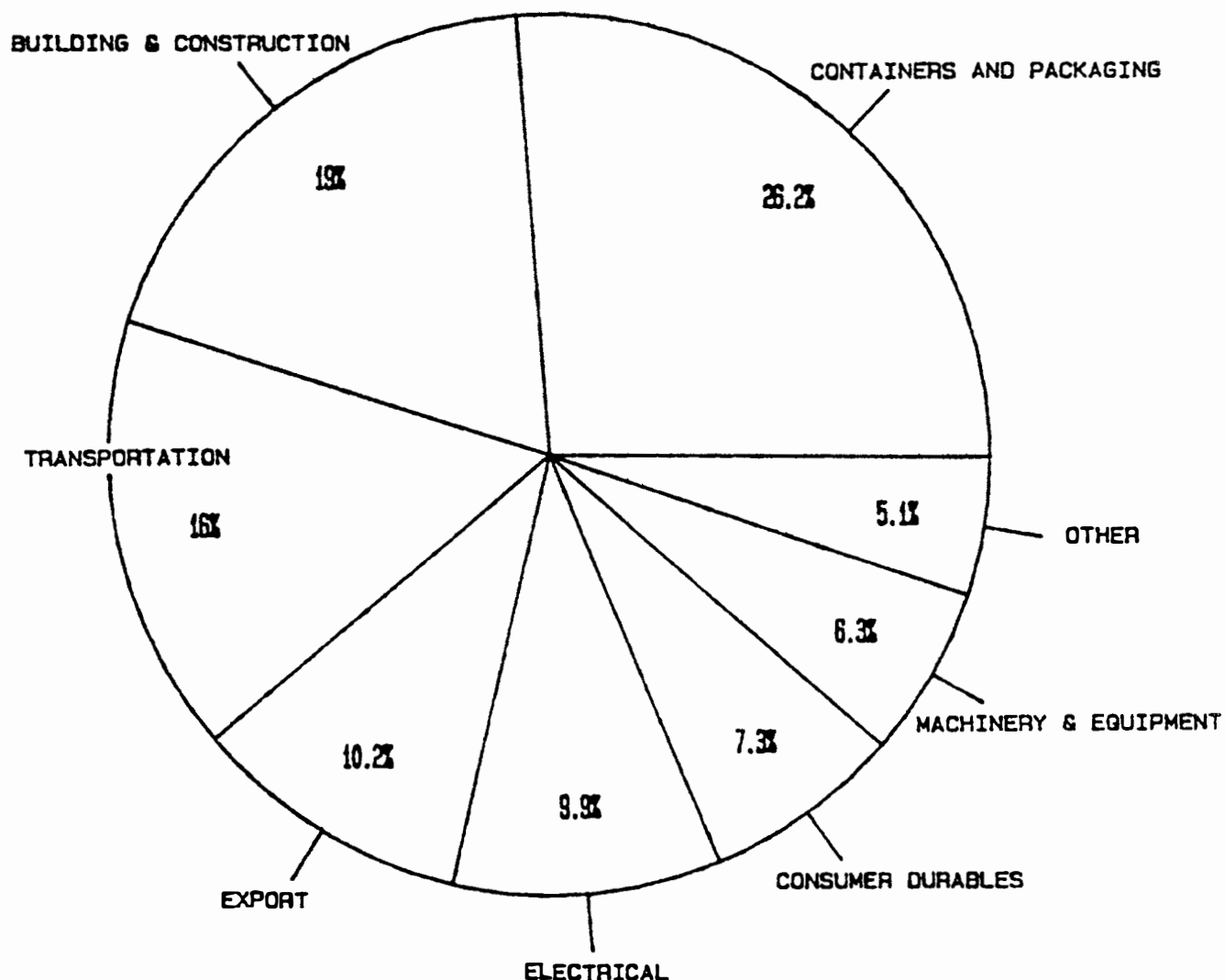
The use of aluminum in the container and packaging industry, a less cyclical area of the economy, has grown to account for the largest share of aluminum consumption in the United States. However, aluminum use in this market is approaching maturity, with not much room for additional growth. Recycling has further reduced the demand for primary smelting capacity.

In 1981, the United States was an importer of 177,610 short tons of ingot and semifabricated ingot, and an exporter of 156,348 short tons of scrap (The Aluminum Association, Inc., 1981). Therefore, the United States was a net importer of higher valued processed aluminum, thus creating an export/import imbalance. Recent reductions in national production will exacerbate this imbalance.

The ore used in the smelting process is bauxite. There are relatively small reserves of bauxite in Europe and North America, with U.S. domestic supplies located largely in Arkansas. About 90 percent of the bauxite used in the U.S. is imported. Suppliers include Guinea, Guyana, Haiti, the Dominican Republic, Jamaica, and Australia. The economies of some of these countries benefit substantially from U.S. bauxite imports.

It will take some time before the current excess inventory of primary aluminum, which has resulted from slowed demand, can be absorbed. According to an aluminum industry research service, domestic producers (particularly those with high operating costs) will utilize these excess inventories while the world-wide price of primary aluminum is less than their cost of production (Tsai-Spector Research Associates, 1982a). In the meantime, 1983 imports of primary ingots from low-cost foreign production may increase as much as 50 percent over 1982 until a supply/demand balance is reached.

FIGURE IV-3.
ALUMINUM CONSUMPTION
BY MAJOR U.S. INDUSTRIES



SOURCE: "PRODUCT NET SHIPMENTS BY MAJOR MARKET, 1971 - 1981," PUBLISHED BY THE ALUMINUM ASSOCIATION IN "ALUMINUM STATISTICAL REVIEW FOR 1981," PAGE 13.

This supply/demand balance is forecast by the end of 1984, resulting from higher demand and stronger aluminum prices. Domestic aluminum producers' operating rates are projected to increase from an estimated 65 percent in 1982 and 63 percent in 1983 to about 83 percent in 1984 (Tsai-Spector Research Associates, 1982a). A stronger than expected economic recovery could improve the outlook further. At the same time, as discussed in the previous section, domestic aluminum producers may face stronger competition from foreign producers than in the past.

(3) Regional Industry Assessment

The Pacific Northwest has approximately 33 percent of national aluminum production capacity (see Table IV-1). The assessment of the Pacific Northwest producers relative to other domestic producers is based on analyses of comparative costs, operating rates and plant modernization plans as an indication of actual and anticipated market strength.

Comparative Cost: Comparative costs are the most important indicator of the national position of the Pacific Northwest producers. This factor will be used in long-range corporate planning regarding continued operation of the plants. If long-range perception exists of a comparative Pacific Northwest cost advantage, the region will retain a major share of national production capacity. If this perception ceases, operating level curtailments or shutdowns can be expected. Remaining plants may become "swing plants" and be used to supplement production elsewhere, rather than be operated as base facilities.

Most variable costs experienced by the industry are equivalent throughout the U.S., with the exception of power and transportation costs. Pacific Northwest producers pay higher transportation costs than other domestic producers since the major domestic aluminum markets are in the Midwest and East, but historically have enjoyed an electricity price advantage over other regions. The net effect has been a cost advantage to Pacific Northwest aluminum producers relative to other domestic producers (Ernst and Ernst, 1976).

Table IV-6 shows the production cost components of a new primary aluminum plant in the U.S. constructed in 1980. (The most recent Pacific Northwest plant came on-line in 1971.) As shown in the table, energy costs comprise 35 percent of total production costs.

The recent increases in the cost of power to Pacific Northwest aluminum companies have changed considerably the comparative cost picture among regions. Table IV-8 shows the estimated 1983 power costs and power cost per pound of output (a function of plant efficiency) by region. The 1983 average electric power cost per pound of aluminum produced in the Pacific Northwest is projected to be second highest among domestic producing regions. This projection, in combination with the continuing transportation cost disadvantage, suggests that Pacific Northwest plants are no longer among the lowest-cost and, therefore, may no longer be the last to experience production cutbacks in periods of slack demand.

TABLE IV-6
ESTIMATED PRIMARY ALUMINUM PRODUCTION COSTS
IN A U.S. PLANT CONSTRUCTED IN 1980 a/

<u>Line No.</u>	<u>Cost Component</u>	<u>Share of Production Costs</u> (Percent)
1.	Primary Materials	43
2.	Energy	35
3.	Labor	13
4.	Operating and Maintenance Materials	3
5.	Plant Overhead <u>b/</u>	6

a/ Hall electrolysis process, capacity of 197,000 tons per year, capital investment of \$400 million.

b/ Calculated as 50 percent of labor costs.

Source: Percentages calculated by BPA, adapted from Sen-Yan Shen, "Energy and Material Flows in the Production of Primary Aluminum," ANL/CNSV-21, Argonne National Laboratory, Argonne, Illinois, 1981, Table 22, page 29.

TABLE IV-7
REGIONAL COMPARISON OF ALUMINUM PRODUCTION POWER COSTS
(Forecast 1983)

<u>Line No.</u>	<u>(a) Region</u>	<u>(b) Total Capacity (000 TPY) <u>a/</u></u>	<u>(c) 1983 Est. Power Cost (mills/kwh)</u>	<u>(d) 1983 Power Cost (cents/lb.)</u>	<u>(e) Est. kwh/ lb.</u>
1.	Pacific Northwest	1,560	24.6 <u>b/</u>	19.4	7.9
2.	TVA <u>c/</u>	895	30.7	28.0	9.1
3.	Ohio Valley	1,338	25.6	19.5	7.6
4.	Northeast	319	10.3	8.6	8.4
5.	Gulf Coast	676	16.1	14.3	8.9

a/ TPY is metric tons per year.

b/ Based on a BPA average rate of 25.9 mills/kwh and some 4 mills/kwh power supplied by Chelan Co. PUD. The actual cost of BPA power is 24.5 mills/kwh.

c/ Includes two plants with 275,000 TPY capacity that are located in the TVA area but served by other utilities.

Source: Column (b): Merner Research, Division of Stuart Coleman and Co., "Projected 1983 Power Costs for Aluminum Producers in North America with Comparisons to 1979," September 3, 1982. Columns (c) and (d): BPA estimates based on above reference.

Estimated information for 1983 on the component costs of aluminum production relative to market price is presented for Pacific Northwest aluminum producers in Table IV-8. Electricity cost is forecast to be 19.4 cents per pound in 1983 (Merner Research 1982; BPA, 1983g). The average nonpower costs for 1983, based on the information in Table IV-9, are projected to be approximately 53 cents per pound, just slightly higher than the projected selling price per pound of aluminum of 52 cents during the first quarter of 1983. Although this may appear to imply that a significant amount of production cutback would occur even if aluminum producers were to receive electricity at no cost, producers are expected to continue operation in order to stockpile product in anticipation of future aluminum price increases.

During the fourth quarter of 1983, the projected selling price is 72 cents. This projection suggests an increase in production due to an expectation of 1984 prices sufficient to cover total production costs and an incentive for stockpiling in anticipation of increases in aluminum prices. The timing of production increases will vary from plant to plant, depending on inventories, individual plant efficiencies, and other considerations.

TABLE IV-8
COSTS OF PACIFIC NORTHWEST ALUMINUM PRODUCTION
RELATIVE TO MARKET PRICE OF ALUMINUM

Line No.	A Cost Category Price	B 1983 CY	
		Estimated Cost/Price a/ (cents/lb.)	
1.	Labor b/	10.0	
2.	Electric Power c/	19.4	
3.	Transportation d/	5.0	
4.	Alumina e/	20.0	
5.	Other Raw Materials f/	11.0	
6.	Other Fixed Costs	7.0	
7.	Total Cost per pound.	72.4	
8.	Price per pound: g/ 1st Quarter, 1983	52.0	
9.	2nd Quarter, 1983	60.0	
10.	3rd Quarter, 1983	65.0	
11.	4th Quarter, 1983	72.0	

a/ 1983 estimates assume same level of production as 1980 (1,550,000 tons).

b/ Index of average hourly earnings in primary metals - Data Resources, Inc. (DRI), Cost Forecasting Review (CFR), 1982:3.

c/ Based on 24.5 mills/kWh and 7.9 kWh/lb. aluminum.

d/ Index of railroad freight costs, DRI - CFR, 3rd Quarter, 1982..

e/ Commodities Research Unit and various industry representatives.

f/ Crude Materials Index, DRI-CFR, 3rd Quarter, 1982.

g/ Price projections taken from: The Spector Report - Aluminum Industry; June 24, 1982.

Source: BPA, Division of Power Requirements, January 1983.

Operating Rates: Comparing operating rates in the Pacific Northwest with operating rates of other plants is an indirect way of evaluating operating costs and other factors that determine plant viability. Other factors that enter into decisions to operate one plant rather than another include purchase and sale contract obligations, local market conditions, labor agreements, and technology constraints. Short-term operating decisions will be influenced by these factors.

The operating rates of Pacific Northwest plants and other domestic producers during two previous recessionary periods are shown in Table IV-9. In 1975, Pacific Northwest aluminum plants operated at an apparent cost advantage over other regions. Pacific Northwest plants typically were curtailed later than other domestic plants, and resumed operation sooner as market conditions improved. In January 1975, early in a period of industry curtailment, Pacific Northwest plants operated at 99 percent of capacity and other domestic producers operated at 94 percent. In August 1975, Pacific Northwest plants were still operating at a high level of capacity (91 percent) but other domestic plants had fallen to only 66 percent.

In January 1982, when total U.S. aluminum production cutbacks were similar in magnitude to August 1975 cutbacks, Pacific Northwest plants operated at 82 percent of capacity. In August 1982, Pacific Northwest plants apparently continued to enjoy a production advantage over other domestic plants. Pacific Northwest plants were operating at 70 percent of capacity, 15 percent higher than other plants throughout the Nation. However, in January 1983 (subsequent to BPA's October 1982 industrial firm power rate increase of 50 percent) Pacific Northwest plants were operating at only 61 percent of capacity, nearly the same rate as other plants throughout the U.S. The capacity utilization spread between Pacific Northwest plants and other plants diminished from 25 percentage points in 1975 to 5 in 1983.

Plant Modernization. Investment in plant modernization is another indicator of industry health. Decisions to invest in new plant or to modernize existing plant depend, quite simply, on whether an adequate return on investment is anticipated. Industry spokespersons have suggested that dramatically rising power costs may alter plant modernization plans, yet expectation of future rate increases is but one of many factors that influence rate of return calculations. Current and anticipated market condition is another major consideration. It is not possible to reliably isolate the many factors that currently are influencing decisions to defer plant investment and modernization.

Although Alcoa currently is completing a \$36 million project at its Wenatchee plant, the company has deferred a \$300 million investment in a new smelter. ARCO completed within the last year a \$42 million modernization program and Martin-Marietta recently completed a \$190 million modernization and plant expansion program. Kaiser is "reexamining" a planned \$600 million modernization program in view of BPA's October 1982 wholesale power rate increase (Jenning, 1982). However, in May 1982, when the anticipated rate increase was lower than the rate which

TABLE IV-9

U.S. ALUMINUM SMELTER CAPACITY AND CUTBACKS: 1975, 1981 AND 1982

Line No.	Time Period	A Production Cutback (000 short tons/yr)	B Plant Capacity (000 short tons/yr)	C Capacity In Use (Percent)
1.	January 1975 a/			
2.	Served by BPA	20	1,591	99
3.	Balance of U.S.	189	3,428	94
4.	Total U.S.	209	5,019	96
5.	August 1975 b/			
6.	Served by BPA	136	1,591	91
7.	Balance of U.S.	1,160	3428	66
8.	Total U.S.	1,296	5019	74
9.	August 1981 c/			
10.	Served by BPA	48	1,716	97
11.	Balance of U.S.	653	3,649	82
12.	Total U.S.	701	5,365	87
13.	January 1982 d/			
14.	Served by BPA	309	1,716	82
15.	Balance of U.S.	1,186	3,649	67
16.	Total U.S.	1,568	5,365	71
17.	August 1982 e/			
18.	Served by BPA	507	1,716	70
19.	Balance of U.S.	1,630	3,649	55
20.	Total U.S.	2,137	5,365	60
21.	January 1983 f/			
22.	Served by BPA	664	1,723	61
23.	Balance of U.S.	1,665	3,819	56
24.	Total U.S.	2,329	5,542	58

a/ Metals Week, January 6, 1975; Oak Ridge Associated Universities, Industrial Energy Use Data Book, 1980, p. 16-37.

b/ Metals Week, August 25, 1975. "Served by BPA" and "Balance of U.S." are estimates.

e/ Metals Week, August 10, 1981.

d/ Metals Week, January 11, 1982. Total includes 73,000 tons per year production cutback that was not identified geographically.

e/ Metals Week, August 16, 1982.

f/ Direct Service Industries, Inc., February 1983 (completed by American Metal Market from aluminum company data; revised January 1, 1983).

was finally implemented, a Kaiser official stated that wholesale rates would not affect the company's improvement program but BPA's "general state of business may affect the timing" of the program (Mendenhall, 1982).

Investment in new plant construction is also an indicator of industry health. In February 1983, Alumax Pacific Corporation announced that it would "indefinitely defer" its proposed \$660 million smelter for Umatilla County, Oregon. The corporation has also dropped plans to purchase land for the smelter site. (Alumax has a power supply contract with BPA; therefore, BPA remains obligated to plan on serving future Alumax load.)

b. DSI Nonaluminum Customers

The nonaluminum DSI's face different markets but still have felt the effects of the recessionary general economy. Several plants (Hanna, Carborundum, and Elkem) have shut down because the current price for their product has made continued operation of their plants uneconomic. As markets improve, resumption of production is anticipated.

One customer (Stauffer) did not renew their contract with BPA, choosing instead to purchase power from a local investor owned utility. If BPA industrial firm power rates increase, other nonaluminum DSI's can be expected to examine this option.

4. Modeled Response to BPA Revenue Alternatives

a. DSI Simulation Model Description

The amount of electricity purchased by the DSI's is a function of several factors relating to price for and cost of producing the products they market. BPA has developed a simulation model which accommodates sensitivity analysis of these factors on future electric loads of DSI's, including nonaluminum DSI's (BPA, 1983d).

The model assumes that Pacific Northwest aluminum producers will operate any available capacity which can produce primary aluminum at a variable cost that is less than forecast market prices. Cost inputs include electrical power, alumina, labor, and other costs. An additional cost input reflects the net disadvantage in transportation costs to major markets which Pacific Northwest aluminum producers face in relation to other areas of the country. These cost inputs are adjusted for each forecast year based on appropriate cost indexes from Data Resources, Inc. (DRI) (DRI, 1982a). Price data are taken from forecasts by Tsai-Spector Research Services, Inc. (Tsai-Spector, 1982b); Commodities Research Unit (Commodities Research Unit, 1982); Paine-Webber (Paine-Webber, 1982); and Chase Econometrics (Chase Econometrics, 1982).

A ceiling on operating levels of aluminum DSI's is based on projections of national capacity utilization. This ceiling is used to reflect the fact that average production costs of Pacific Northwest plants have risen from the "low-cost" range to the "medium to high cost" range. Therefore, operating rates in the Pacific Northwest are assumed to be at the forecast national levels.

Because primary aluminum production represents over 90 percent of the DSI load and revenue, the forecasting effort was focused on aluminum. The load of the other DSI's which are comprised of a diverse group of smaller industries, were assumed to gradually recover up to capacity in line with the general economic recovery (except in the LRIC revenue alternative). In general, these plants are assumed to resume production when the price of output (product) exceeds production cost, including costs of electricity.

b. Forecast DSI Loads Under Revenue Level Alternatives

The DSI simulation model generated forecast DSI loads from calendar year 1983 through 1988 under three revenue level alternatives. The cost of electricity to the DSI's under the base rate alternative is assumed to be 2.9 mills per kilowatthour (the average rate paid by DSI customers during FY 1979 (BPA, 1981c)) for the entire forecast period. This alternative simulates the effects of establishing DSI rates for the CY 1983-CY 1988 period at their 1974 level, assuming current plant capacity. It did not simulate what current plant capacity would be if the 1974 DSI rates were presently in effect.

The proposed alternative assumes the current rate of 24.5 mills per kilowatthour for January through October of 1983; the proposed average rate of 24.9 mills per kilowatthour from November 1, 1983, through June 30, 1984; and 25.8 mills per kilowatthour from July 1, 1984, through the end of 1988. In order to approximate these assumptions in loading the DSI simulation model, a weighted rate of 24.5 mills per kilowatthour was input for CY 1983, 25.4 mills per kilowatthour for CY 1984, and 25.8 mills per kilowatthour thereafter.

The proposed DSI rates closely approximate current DSI rates. Therefore, the results of the proposed alternative would closely approximate the effects of a "no action" alternative, which would assume the current estimated average rate of 24.5 mills per kilowatthour to be in effect for the entire 1983-1988 period.

In the LRIC alternative, the current rate of 24.5 mills per kilowatthour covers the first 10 months of 1983, with the LRIC price of 42.6 mills per kilowatthour (BPA, 1983f) for the remainder of the forecast period. Therefore, in loading the DSI simulation model, a weighted rate of 27.5 mills per kilowatthour was input for 1983 under the LRIC alternative, and 42.6 mills per kilowatthour for subsequent years.

The DSI simulation model assumes a general increase in demand (during the six-year period 1983 to 1988) for materials produced by the DSI's because of reductions in current excess inventories and a general upturn in the economy beginning in 1983. The current demand, particularly for aluminum, would not likely support maximum operating levels even with low cost electricity. The increases in demand and product prices, however, are expected to be strong enough to offset or mitigate the effects of any electric rate increases to the DSI's. Therefore, increases in production and in DSI loads can occur in spite of increasing electricity costs.

Table IV-10 shows the total DSI and the aluminum DSI forecast loads for calendar years 1983 through 1988 under the four revenue level alternatives. Under the base rate alternative, total DSI loads would be expected to increase from 2,508 average megawatts in 1983 to 3,795 average megawatts in 1988. Aluminum DSI loads are forecast to increase from 2,348 average megawatts in 1983 to 3,405 average megawatts in 1988. These load increases should occur as a result of increases in operating rates from current levels and startups of existing and new plants, largely in response to a higher demand for products and lower electric costs than the DSI's are presently paying. Under this scenario, aluminum plants now considered to be "swing" plants would likely be among the last in the country to be curtailed. The proposed Alumax aluminum plant (320 average megawatts) would be constructed and placed in operation during the period under the base rate revenue assumptions. Operating rates of nonaluminum DSI's would increase to full capacity in 1986 and remain at full capacity through 1988.

Under the proposal alternative, total DSI loads are projected to increase from 2,104 average megawatts in 1983 to 3,462 average megawatts in 1988. The aluminum portion of these forecast DSI loads increases from 1,944 average megawatts to 3,072 average megawatts during the period. In this alternative, operating rates would be much lower in the beginning of the forecast period than under the base rate alternative, but would increase at a fast rate. A larger portion of the Pacific Northwest aluminum capacity would remain "swing" plants in times of slowed demand (such as the present) than under the base rate alternative, but would be brought into full production during the high demand periods (such as the end of the forecast period). The addition of the Alumax plant would be anticipated by the end of the period. As under the base rate alternative, nonaluminum DSI's are projected to reach full operating rates by 1986, on the strength of a general upturn in the economy.

The electricity price assumptions in the LRIC alternative produce a projected general decrease in total DSI loads, from 1,647 average megawatts in 1983 to 1,014 average megawatts in 1988, and in aluminum DSI loads, from 1,487 average megawatts in 1983 to 829 average megawatts in 1988. Under this alternative, the increase in demand for DSI products does not totally offset the effects of the higher price for electricity. In fact, only three of the existing aluminum plants would be expected to remain in operation after an LRIC rate went into effect. Nonaluminum DSI's are forecast to operate at one-half of capacity beginning in 1984 under this alternative.

Of BPA's DSI customers, the aluminum industry is most responsive to the price of electricity, due to its energy intensiveness and the potential for regional aluminum plants to become swing plants as electricity costs increase. The results of the DSI load forecasts reflect this. The forecast non-aluminum DSI load of 390 average megawatts in 1988 under the Base Rate alternative is 100 percent greater than the corresponding forecast load of 185 average megawatts in 1988 under the LRIC alternative. By comparison, the aluminum DSI load under the Base Rate alternative is forecast to be 3,405 average megawatts in 1988, about 300 percent greater than the projected 829 average megawatts of aluminum DSI load in 1988 under the LRIC alternative.

TABLE IV-10

FORECAST DSI LOADS UNDER REVENUE LEVEL
ALTERNATIVES, CY 1983 THROUGH CY 1988

Line No.	Revenue Alternative	(a)	(b)	(c)	(d)	(e)	(f)
		Calendar Year					
		1983	1984	1985	1986	1987	1988
		(a MW)	(a MW)	(a MW)	(a MW)	(a MW)	(a MW)
1.	<u>Base Rate:</u>						
2.	Aluminum	2,348	3,044	3,045	3,045	3,365	3,405
3.	Nonaluminum	160	280	366	390	390	390
4.	Total DSI	2,508	3,324	3,411	3,435	3,755	3,795
5.	<u>Proposal a/:</u>						
6.	Aluminum	1,944	2,571	2,960	3,013	3,034	3,072
7.	Nonaluminum	160	280	366	390	390	390
8.	Total DSI	2,104	2,851	3,326	3,403	3,424	3,462
9.	<u>LRIC:</u>						
10.	Aluminum	1,487	642	806	814	822	829
11.	Nonaluminum	160	185	185	185	185	185
12.	Total DSI	1,647	827	991	999	1,007	1,014

a/ Proposal alternative is also reflective of "no action" assumptions, under which the current average DSI rate of 24.5 mills per kilowattnour would be in effect for the entire 1983-1988 period.

Source: DSI Simulation Model, Bonneville Power Administration, March 1983

E. Analysis of Industrial Customers of Public and Private Utilities

The industrial customers of Pacific Northwest retail utilities encompass a wide variety of industries, which vary in size, number of direct employees and energy intensiveness. Some of these basic industries developed as a result of the region's indigenous resources. Others located in the Pacific Northwest because of favorable proximity to markets, quality of the labor force, availability of low cost electricity, and other factors. However, these industries are all affected by energy costs to some degree.

This section addresses the relationship of power costs to the region's retail industrial customers. The first part presents an assessment of product demand outlook for the industries. In the second part, the relationship of BPA wholesale rates to production levels of retail industries is analyzed. Finally, the industries' options for mitigating the effects of power costs on their profitability are examined.

1. Outlook for Regional Industries

a. Lumber and Wood Products

The entire wood products industry has been at depressed levels due to the depressed housing market. Nationally, housing starts reached 2.023 million in 1978, but dropped to 1.303 million units in 1980. National forecasts project that housing starts will increase to a level of 1.98 million units by 1986, then gradually decrease to an average 1.6 million units during the 1990s (DRI, 1982b). Not only are housing starts not projected to reach the levels of the late 1970's, but housing units are anticipated to be smaller in size on the average, requiring less volume of wood products per unit.

The Pacific Northwest is expected to continue to experience increasing competition from the Southeastern lumber producing areas. The Pacific Northwest faces higher transportation, stumpage, and labor costs relative to the Southeast region. In addition, the larger proportion of private ownership of timber lands in the Southeast places fewer restrictions on supply relative to the Northwest, whose timber resources are to a larger degree government owned and more subject to regulatory limits. Some level of uncertainty exists regarding these regulatory limits and, therefore, the Pacific Northwest's ability to more easily respond to fluctuations in demand. The factors responsible for this uncertainty include the budgetary resources of the Forest Service, changes in the estimates of current and future timber resources, changes in the laws governing management of the resources and adoption of exceptions to timber harvest provisions specified in current legislation.

Another area of uncertainty is the export of logs or wood products. Most of the Pacific Northwest's current exports go to Japan in the form of logs. This has been opposed by Northwest mill owners who fear the loss of raw materials for production and potential markets for their products.

A recent forecast projected employment and production in the Pacific Northwest lumber and wood products industry on the basis of six major factors: (1) levels of timber harvest in the region; (2) national

demand for wood products, particularly in housing; (3) changes in production processes, including those which change the output per employee, or yield per cubic foot of log; (4) shifts in the types of wood products produced; (5) competition for market with other regions of the U.S. and Canada; and (6) export of logs and wood products to Japan or other countries (Northwest Power Planning Council, 1982b). The medium case of the forecast assumed a production recovery from the current recession beyond 1980 levels, but below levels of the late 1970's. The projected average annual growth rates in production from 1980 to 2000 among four major sectors of the lumber and wood products industry range from .2 percent for lumber (SIC 2421), to 1.2 percent for plywood (SIC 2436) and particleboard (SIC 2492), and 1.9 percent for all other firms in the lumber and wood products group. Total employment in lumber and wood products were projected to increase to 151,300 in 1985 from its 1980 level of 139,100, with a subsequent decrease to 137,100 in 2000 (Northwest Power Planning Council, 1982b).

b. Pulp and Paper Industry

Nationally, the demand for paper products is expected to be strong. The outlook for the Pacific Northwest is favorable with regard to proximity to markets in the West. The Pacific Northwest industry also has access to ports to serve world markets, as well as the largest inventory of the long-fiber softwoods preferred by this industry. While some factors, such as environmental regulation, labor costs, and resource cost and availability are not as favorable as in the Southeast, the Pacific Northwest pulp and paper industry is projected to experience long term growth in both production and direct employment. For the period 1980 to 2000, average annual growth in production levels in pulp (SIC 2611) and paper (SIC 2621) are forecast at 1.1 percent and 2.8 percent, respectively. Total pulp and paper employment, 30,100 in 1980, is forecast to grow to 36,100 in 2000 (Northwest Power Planning Council, 1982).

c. Chemicals and Allied Products

The chemical and allied products industry (SIC 28) is comprised of a diverse group of chemical manufacturers and processors. Historically, the largest consumers of electricity in this group have been the elemental phosphorous industry and the chlorine and caustic soda industry.

Annual average growth in production of elemental phosphorous in the Pacific Northwest from 1980 to 2000 has been projected at 1.0 percent (Northwest Power Planning Council, 1982b). In response to a survey of the two non-DSI elemental phosphorous producers in the region, one of the companies cited limiting factors for its industry's growth. These included the cost and availability of electricity, mature markets for their product, and little planned expansion of production capacity in the near future.

The production of chlorine and caustic soda is accomplished simultaneously through a single electrolytic process, separating salt into the two co-products. Although the two products are derived from the same process, the market outlook for the two products differs substantially. In the past, chlorine has held the stronger market and higher price. Expansion plans were based on growth in chlorine demand. As little as ten years ago, caustic soda was considered an undesirable by-product and, for years, producers sought to

develop a commercial process to produce chlorine without producing caustic soda. In the last few years, however, the price of caustic soda has risen and supplies have tightened, while chlorine demand has dropped and prices have remained stable.

Industry experts have predicted growth rates for national chlorine demand in the 1980's to range from an average of 1 to 3 percent per year, whereas demand for caustic soda could increase at rates ranging from 2.5 to 5 percent (Chemical Marketing Reporter, 1981a). This is slower than the rate of growth in chlorine production from 1960-1980, which averaged 4.1 percent per year. From 1970 to 1980, however, production increased at an annual rate of only 1.6 percent (The Chlorine Institute, 1982). The outlook for chlorine has been affected by environmental regulations on effluent standards. Pulp and paper producers may substitute other chemicals in pulp bleaching to reduce emissions (Chemical Marketing Reporter, 1981b). The outlook for caustic soda is more favorable because it has a broader base of end-uses. Since one of the fastest growing end uses is in the neutralization of waste acids, tougher environmental standards would enhance the outlook for caustic soda. Soda ash can be substituted for caustic soda, and although the initial investments required to handle soda ash are high, projections of relative price increases of caustic soda and soda ash favor some conversion to soda ash (Chemical and Engineering News, 1982). Production of chlorine and caustic soda, however, is likely to be constrained by the price of chlorine, since it is more difficult to store.

Collectively, the firms in the chemical and allied products industries are expected to experience long-term growth. Total direct employment for this group is projected to be 17,700 in 2000, increasing from 13,800 in 1980 (Northwest Power Planning Council, 1982b).

d. Transportation Equipment

The transportation equipment industry includes firms involved in the manufacturing of aircraft, ships and boats, motor vehicles, railroad equipment, and travel trailers. The manufacturing of aircraft accounts for nearly three-fourths of the Pacific Northwest's employment in the transportation equipment industry. Therefore, the outlook for this industry group is strongly dependent on the aircraft manufacturing sector's outlook.

Because of recent weaknesses in the airline industry and declines in passenger miles, aircraft orders have dropped. It is expected that orders will increase when economic conditions and airline financial conditions improve. Boeing has developed national attention with its fuel efficient 757 and 767 model aircraft. With the departure of Lockheed from the manufacture of commercial aircraft and the lag in expansions of Airbus production capacity, Boeing is projected to retain a marketshare exceeding 60 percent over the next five years. The total market for commercial aircraft during this period is not projected to reach the levels of the late 1970s, however. By 1990, a new, expanded demand cycle is projected to begin, involving new technology (Greenslet, 1982). By 2000, total employment in the Transportation Equipment sector in the Northwest, including Aerospace, is projected to increase to 112,900 from its 1980 level of 109,300 (Northwest Power Planning Council, 1982b).

e. Food and Kindred Products

This industry is affected by demands for processed foods in this country and in countries adjacent to the Pacific Ocean (Pacific Rim countries). The availability and cost of raw food products from the region's agriculture and fishing industries is an additional factor.

The Pacific Rim countries recently have become an expanding market for processed foods. To the extent that this trend continues, the Pacific Northwest processors will enjoy a comparative advantage in serving that market because of their proximity to ports. The supply of fish and agricultural products in the Pacific Northwest remains somewhat uncertain, due to recent poor commercial fishing conditions and a slowing in the expansion of irrigated acres. Yield improvements in agriculture, however, are expected to compensate for the slowing in expansion of irrigated acreage. Total employment in the food and kindred products group in the region, 73,200 in 1980, has been forecast to increase to 90,800 in 2000 (Northwest Power Planning Council, 1982b).

f. Electronics

The electronics industry has been the fastest growing manufacturing industry in the nation and the Pacific Northwest. This industrial group includes Professional Instruments, Electrical Machinery and Computing Equipment. Employment in electronics has quadrupled in the region since 1960, although it only increased by 59 percent in the nation. The Electronics industry employed 86,400 people in the region in 1980. Total employment in this sector in 2000 has been projected at 176,000, reflecting expected continued high growth in the Pacific Northwest (Northwest Power Planning Council, 1982b).

2. Relationship Between BPA Wholesale Power Costs and Industrial Customers of Retail Utilities

The industrial customers of the Pacific Northwest retail utilities receive power either from public utilities who purchase all or a portion of their power requirements from BPA under the priority Firm rate with possible additional purchases under the New Resources rate, or from investor-owned utilities (IOU's) who use their own power sources to serve industrial loads. Some of the IOU's participate in the farm and residential exchange program, through which they can supply irrigation loads, and some purchase BPA's firm capacity. Most potential direct impact of BPA's rates, however, would likely be concentrated on industrial customers of public utilities who purchase the bulk of their power from BPA under the Priority Firm rate.

Several factors precluded indepth modeling of potential wholesale rate impacts to individual public agency industrial customers or industry groups. First, these industries are comprised of a heterogeneous group of companies with varying levels of energy intensiveness. Second, because of confidentiality constraints, BPA did not have access to pertinent data for the various industry groups or for individual companies. Third, there are inherent difficulties in modeling the manner in which wholesale rate levels and rate designs are passed through to consumers by retail utilities.

Finally, potential changes in the demand for products may introduce uncertainty to a forecast of wholesale rate impacts to retail industrial customers.

However, BPA's Supply Pricing Model was used to develop estimates of composite public agency industrial rates under each of the five revenue level alternatives described in Section II.B. These projections are shown in Table IV-11. As the table indicates, increases in the retail industrial rates do not correspond directly to increases in the Priority Firm rate. For the base rate, the public agency retail industrial rates increase from FY 1981 to FY 1985; despite the absence of Priority Firm increases during the period under this alternative. This is due to the inflation of costs other than BPA's power costs.

Under the proposed alternative, a Priority Firm increase of 27 percent from 1983 to 1985 is projected to result in a corresponding retail industrial rate increase of only 18 percent. The direct financing alternative, which assumes a 48 percent Priority Firm rate increase over the same period, results in a 30 percent increase in the average industrial rate of public utilities. For the LRIC alternative, a 137 percent increase in the Priority Firm rate results in an increase in the rate to public agency industrial customers of 80 percent. In fact, the LRIC case indicates an increase of only 17.2 mills per kilowatthour to industrial consumers from FY 1983 to FY 1985 as a result of a Priority Firm increase of 24.6 mills per kilowatthour over the same period.

These differences between wholesale rate increases and corresponding retail industrial rate increases reflect some basic characteristics of the relationships of BPA's wholesale power and retail customers. First, the cost of wholesale power is only a portion of the total system costs which public agencies must recover, partially accounting for the lack of a "one-for-one" relationship between wholesale and retail power costs. Second, some of the public utilities own relatively low cost hydro facilities which serve a portion of their loads and help to mitigate the effects of wholesale rate increases. Furthermore, to the extent that industrial customers of retail utilities decrease their load in response to price increases, generating utilities will displace purchases from BPA when possible and continue to operate their low cost hydro. Therefore, the low cost hydro accounts for a proportionately higher share of power used to serve loads (assuming sufficient stream flow conditions) as customers decrease their power consumption in response to price. Finally, the debt service requirement for public utilities who are participants in WNP-4 and -5 decreases in FY 1985, offsetting increases in BPA wholesale power costs and other costs facing the utilities.

TABLE IV-11

Comparison of Wholesale Priority Firm
Unit Rates and Public Utility Industrial Unit Rates,
FY 1981 through FY 1985, by Revenue Level Assumption

FY	Base Rate		No Action		Proposal		Direct Financing		LRIC	
	Priority	Retail	Priority	Retail	Priority	Retail	Priority	Retail	Priority	Retail
	Firm	Ind	Firm	Ind	Firm	Ind	Firm	Ind	Firm	Ind
	(mills/kWh)		(mills/kWh)		(mills/kWh)		(mills/kWh)		(mills/kWh)	
1981	3.7	7.0	7.8	9.8	7.8	9.8	7.8	9.8	7.8	9.8
1982	3.7	7.2	11.4	12.6	11.4	12.6	11.4	12.6	11.4	12.6
1983	3.7	11.4	18.0	21.6	18.0	21.6	18.0	21.6	18.0	21.6
1984	3.7	12.9	18.0	23.2	21.9	25.9	25.3	28.2	42.6	40.0
1985 <u>a/</u>	3.7	11.9	18.0	22.2	22.8	25.5	26.6	28.1	42.6	38.8

Source: BPA Supply Pricing Model Runs, March and July 1983.

a/ Decreases from FY 1984 to FY 1985 in the projected public retail industrial unit rates reflect the decrease in FY 1985 of WNP-4 and -5, debt service among participant utilities.

The results in Table IV-11 represent composite unit rate estimates under varying assumptions. Several factors would determine ultimate impacts of wholesale rate levels to an industrial customer. First, to the extent that power costs are a factor, the impacts to the customer would be partially dependent upon the characteristics of its servicing retail utility. A utility with its own generating resources would need to pass on less of an increase on a per-kilowatthour basis to recover BPA priority firm costs than would a utility whose total loads are served with priority firm power. Also, utilities vary in their rate design. Rates which tend to recover more costs through fixed charges would tend to have less of an effect on high load factor customers such as industrial users than would rates which attempt to recover proportionately more revenue through energy charges. Furthermore, rate levels themselves, which are dependent upon the utilities' total costs, inclusive of power costs, distribution costs, and other costs, vary among utilities. Second, impacts to industries are dependent upon factors in addition to the costs of electricity. The level of energy intensiveness, operational flexibility, and potential capability for alternate fuel use are determinants of sensitivity to electricity price. There may be other costs of production aside from energy costs which may be either more volatile or account for a larger share of total costs. In addition, the level of product demand and, therefore, price for an industry's product is a major factor. Those industries with slim profit margins would be expected to be most sensitive to changes in product demand or production costs, including power costs.

3. Industry's Mitigating Options

There are a number of factors which influence profitability of an industry, including product demand, domestic and foreign competition, and production costs. Where an industry's competitive edge is dependent upon reducing its power costs, it may have one or more options. First, it may be to the industry's advantage to adopt an alternate fuel capability. Second, the servicing retail utility's rate structure may make off-peak consumption an economic alternative. There may be some opportunity for purchasing cheaper nonfirm (interruptible) power to serve a portion of its load, or to switch to on-site generation (such as cogeneration) to provide part of its power needs. For some industries, reduction of power consumption by changing its product mix toward products requiring less energy to manufacture or process, substituting other resources (labor, materials) for energy, or investing in more energy efficient equipment may be viable options. In some cases, it may be necessary to reduce electricity consumption with the possibility of laying off of workers.

Where modifying the consumption of electricity is not feasible, or sufficient to mitigate impacts of electricity costs, an industry may need to choose among other alternatives. It may absorb a larger share of the costs by reducing its profit margin, stockholder benefits or employee compensation. It may be able to pass on some additional costs to the consumer. Finally, an industry may expand or branch elsewhere, relocate to a lower cost area, or cease operation altogether.

F. Pacific Southwest Market Study

The Pacific Southwest is a major market for BPA's surplus capacity and energy. The majority of BPA sales to the Pacific Southwest are made to utilities within California. During calendar year 1982, California accounted for over 99 percent of BPA nonfirm energy sales to the Pacific Southwest, and 100 percent of surplus firm energy sales and capacity transactions (BPA, 1983b). Therefore, the emphasis of this section is on the historic and future relationship of California to the Pacific Northwest electric system.

1. Historic Importance of Pacific Northwest Sales to California

California's electric system is heavily reliant on oil and gas fired generation to serve its load. In 1981, oil and gas generation supplied approximately half of the capacity and energy necessary to serve the state's electric loads (California Energy Commission, 1982, pp. 7-2, 3). These resources have been considerably more expensive than BPA's secondary energy rate. Between 1965 and 1974, BPA's rate for secondary energy was 2 mills per kilowatthour. In 1974, the secondary energy rate increased to 3.0 mills per kilowatthour during the summer and 3.5 mills per kilowatthour during the winter. Following the 1979 rate increase, secondary nonfirm energy purchased for the purpose of displacing thermal generation was priced at one-half the decremental cost of the purchaser's highest cost resource with the condition that the rate not exceed 20 mills per kilowatthour or be less than 4.5 mills per kilowatthour for offpeak hours. The minimum charge for peak hours was 6.5 mills per kilowatthour. Average revenue under the current nonfirm rate during FY 1983 is projected to be 11.2 mills per kilowatthour. Revenue produced under the proposed BPA nonfirm energy rate is forecast to average 14.6 mills per kilowatthour during the period November 1, 1983, through June 30, 1984, and 15.1 mills per kilowatthour between July 1, 1984, and July 1, 1985. Therefore, BPA's proposed nonfirm rate would increase the average cost of nonfirm energy between 30 and 35 percent.

When the Northwest/Southwest Intertie became operational, oil fired generation in California had incremental operating costs of 3 to 4 mills per kilowatthour. In 1979, average operating costs had increased to 35 mills per kilowatthour for conventional fossil fuel (oil and gas) fired steam turbines and 52 mills per kilowatthour for fossil fuel fired peaking units. BPA estimates the end of year 1984 incremental operating cost of fossil fuel fired generation at 58 mills per kilowatthour for a conventional steam turbine and 85 mills per kilowatthour for a peaking unit. This represents an increase in operating costs since 1979 of 66 percent for conventional fossil fuel fired generation and 63 percent for fossil fuel-fired peaking generation.

California currently utilizes over 18,000 MW of oil and gas generation capacity to serve its summer peak loads, even while all its large thermal baseload resources are operating and it is receiving nearly 2800 MW of capacity from the Northwest (Meek, 1983). To the extent that California utilities can purchase surplus energy and capacity from adjoining regions, many of the financial and environmental costs associated with operation of these high cost units can be avoided.

The characteristics of the California and Pacific Northwest electric loads and systems encourage transactions involving power sales and

capacity/energy exchanges. Daily peak loads in the Pacific Northwest decline from about 27,500 MW in the winter to under 19,000 MW in the summer. Conversely, California's peak loads grow from 25,500 MW in the winter to 36,000 MW in the summer months, when the Pacific Northwest has an abundance of hydroelectric capability from seasonal stream flows (Meek, 1983).

California utilities' contracts with each other and with sources outside of California accounted for 15 percent of peak capacity in 1982. (California Energy Commission, 1983). California has also purchased large amounts of surplus energy from other areas. Table IV-12 shows Pacific Northwest sales, including BPA sales, to California during the period 1968 through 1982. During the past 10 years, Pacific Northwest sales of nonfirm energy to California have averaged over 14,000 gigawatthours per year. BPA has supplied an average of 43 percent of these sales (over 6,000 gigawatthours).

2. Future Load and Resources Outlook

Table IV-13 shows projected statewide load growth from 1980 to 1994, along with load growth for individual California utility systems. These systems include Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), San Diego Gas and Electric (SDG&E), Sacramento Municipal Utility District (SMUD), Department of Water Resources (DWR), the Burbank, Glendale and Pasadena systems, Western Area Power Administration (WAPA), and composite totals for all other systems. California statewide demand and energy load growth are forecast for this period at about 9,000 MW and 6,000 average MW, respectively.

Despite this projected load growth, the share of oil and gas fired generation is expected to decrease considerably. California policy specifies that by 1992 no more than one-third of California's electricity generation should be derived from natural gas and oil to lessen the state's vulnerability to potential supply disruptions. The various utilities collectively are planning to retire a large portion of these units, some of them early. The current State resource plans include additions of wind, solar, biomass, and geothermal generation, along with a limited number of remotely based nuclear and coal units, both in-state and out-of-state. Over the next 20 years the proportion of oil and gas generation is expected to decline from 50 percent to 23 percent of installed capacity and from 48 percent to 16 percent of energy production (California Energy Commission, 1983).

Table IV-12
NORTHWEST NONFIRM SURPLUS ENERGY SALES TO CALIFORNIA

Calendar Year	From BPA (GWh)	From Other Utilities (GWh)	Total (GWh)	(aMW)
1982	17,147	16,410	33,557	3,831
1981	7,749	19,442	27,191	3,104
1980	3,744	6,094	9,838	1,123
1979	715	5,348	6,063	692
1978	5,952	10,402	16,354	1,867
1977	0	3,642	3,642	416
1976	15,543	6,807	22,350	2,551
1975	8,750	7,309	16,059	1,833
1974	6,417	6,392	12,809	1,462
1973	66	1,405	1,471	168
1972	3,394	5,062	8,456	965
1971	2,375	2,683	5,058	577
1970	446	1,762	2,208	252
1969	69	1,801	1,870	213
1968	<u>159</u>	<u>1,472</u>	<u>1,631</u>	<u>186</u>
Total	72,526	96,067	168,593	19,246
1972-82 Average	6,316	8,028	14,344	1,637

Source: Meek, Daniel W., 1983, Pacific Northwest Conservation for California: The Mutual Benefits of Long-Term Cooperation (Third Draft), California Energy Commission, February.

Table IV-13
CALIFORNIA ELECTRICITY DEMAND/CONSUMPTION

<u>Utility</u>	<u>Ownership</u>	1980 <u>MW</u>	<u>aMW</u>	1994 <u>MW</u>	<u>a/</u> <u>aMW</u>
PG&E <u>b/</u>	IOU	13,660	7,271	15,014	9,033
SCE	IOU	12,926	6,782	16,937	9,219
LADWP	Municipal	4,070	2,004	5,162	2,537
SD&E	IOU	2,018	1,109	2,783	1,506
SMUD	Public	1,574	611	2,208	804
DWR	State	454	366	888	1,032
B-G-P <u>f/</u>	Municipal	625	269	889	409
WAPA <u>c/</u>	Federal	1,050	983	1,152	1,207 <u>d/</u>
Other <u>f/</u>	Various	<u>557</u>	<u>282</u>	<u>673</u>	<u>349</u>
Total		35,884	18,694	44,589	24,907

a/ Utility projections. The CEC forecasts slower growth for most of these utilities.

b/ Incorporates all publicly-owned utility loads within PG&E's overall service area (including WAPA-served loads), except those of SMUD and DWR.

c/ Not additive. WAPA sells power mostly to publicly-owned utilities within PG&E's overall service area.

d/ Approximation.

e/ CEC staff forecast.

f/ Burbank, Glendale, and Pasadena.

Source: Meek, Daniel W., 1983, Pacific Northwest Conservation for California: The Mutual Benefits of Long-Term Cooperation (Third Draft), California Energy Commission, February.

In addition to planned resources, there is additional potential for imports of surplus capacity and energy from adjoining states. California utilities expect to purchase 7,000 gigawatthours annually over the next 20 years from neighboring Southwest states (California Energy Commission, 1983). This area has a large amount of surplus, mostly from coal fired units. While more expensive than surplus power from the Pacific Northwest, the availability of this power is expected to be more constant than the surplus power from the Northwest hydroelectric system which is largely dependent upon varying streamflow conditions. As is the case with the Pacific Northwest, however, much of the potential for additional imports to California is currently subject to such constraints as interstate negotiations and transmission intertie limitations.

To the extent that California utilities can obtain additional capacity and energy surpluses from the other Southwest states and from the Pacific Northwest during the next few years, it can reduce the operation of some of its existing resources and postpone other resource additions. According to one source, the potential exists to displace operation of all the oil and gas generation capability and, in addition, to avoid building 1700 average megawatts of coal and hydro resources. (Meek, 1983). In fact, imports of out-of-state surpluses are regarded as one of the preferred resources. The California Energy Commission recently recommended that utilities explore increased utilization of surplus electricity from out-of-state sources (California Energy Commission, 1983).

G. Residential Consumers

An increase in BPA's wholesale rates indirectly affects residential consumers. These effects on individual consumers depend on: (1) the proportion of each utility's total costs devoted to purchase of BPA power; (2) the utility's retail rate structure; and (3) characteristics of the individual residential consumer. Because residential consumers are unable to pass along rate increases to other customers (as do most commercial/industrial businesses), these users ultimately experience the effect of a BPA rate increase. As mentioned in Chapter II, the impacts of higher electricity prices are most severe for low-income residential consumers including elderly poor on fixed incomes. This conclusion is based on the following analysis of the historic relationship of household energy costs to income level.

Table IV-14 shows on a national scale, by income level, the percent of income before taxes devoted to energy expenditures in 1979. The proportion of income spent by the lowest income households for electricity and other energy in 1979 was more than seven times greater than the highest income households. In 1979, households with incomes less than \$5,000 spent 10.8 percent of their resources on electricity, while those earning over \$35,000 spent 1.4 percent on electricity. This relationship also holds true for other energy sources. High income households spent only 1.0 percent and 1.9 percent of their incomes on natural gas and fuel oil, respectively. Conversely, for the lowest income households, natural gas and fuel oil expenditures were 5 and 12 percent of their incomes, respectively. Thus, an increase in the cost of energy will have a greater proportional impact on low income consumers because energy costs consume a greater portion of their budget. Further supporting analysis is presented in BPA's 1982 Final Rate Proposal: Environmental Impact Statement (BPA, 1982j, pp. 145-150).

TABLE IV-14
HOUSEHOLD ENERGY EXPENDITURES AS PERCENT
OF AVERAGE ANNUAL INCOME, 1979 a/

Line No.	Income Level	A	B	C	D
		Primary Heating Fuels			Overall Average <u>b/</u>
		Elect.	Natural Gas	Fuel Oil	
1.	Less than \$ 5,000	10.8	5.0	12.0	9.8
2.	\$ 5,000 - \$ 9,999	5.4	2.7	7.5	5.9
3.	\$10,000 - \$14,999	2.9	1.8	4.2	3.7
4.	\$15,000 - \$19,999	2.5	1.3	2.8	2.9
5.	\$20,000 - \$24,999	1.8	1.3	3.3	2.5
6.	\$25,000 - \$34,999	1.9	0.9	2.2	2.1
7.	\$35,000 - or more	1.4	1.0	1.9	2.0

a/ Income before taxes for households in Western Region (Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming).

b/ Includes natural gas, electricity, fuel oil, kerosene, and liquid petroleum gas.

Source: U.S. Department of Energy, 1981e, Residential Energy Consumption Survey, Part II: Regional Data, Energy Information Administration.

H. Environmental Consequences of Generation Facilities

A major consequence of an increase in the price of electricity is a decrease in the growth of consumption of electricity. Over time, a slower rate of growth in the demand for electricity would either postpone or eliminate the need for new generation facilities. BPA's models project future regional demand for electricity in response to alternative electricity prices as well as a mix of resources adequate to meet forecast demand. Future regional generation needs will be met from a wide variety of potential resources including conservation, hydroelectric, cogeneration, geothermal, combustion turbines, and conventional coal-fired and nuclear facilities (see Chapter II.B.3.g.). The following discussion presents information on the effects of these resources and was used to form the basis for the analysis of the environmental effects of changes in generation requirements presented in Chapter II.

1. Conservation

Evaluation of environmental impacts from energy conservation measures involves consideration of a variety of impacts to indoor residential and commercial surroundings and to the outdoor environment. (For detailed discussions of conservation impacts (see BPA 1981g and 1982f). The concern for impacts to indoor surroundings is twofold. First, certain materials

typically used in energy conservation measures, whether applied to existing or new structures, can increase the amounts of various types of emissions from materials within a building. Second, the various measures can, in the absence of air-to-air heat exchange units, result in reduced rates of air changes (indoor-outdoor air exchange) which transport potentially harmful emissions outdoors. The reduced air flows can result in higher accumulations of emissions which could result in adverse health effects given long periods or high concentrations of exposure.

Radon is a radioactive gas which is a decay product of uranium. Radon and its progeny, which are products resulting from decay of radon itself, have been, at sufficient levels, linked with lung cancer, birth defects, and genetic damage. The effects of radon exposure seem to be cumulative. Sources of radon emissions include rock, soil and ground watersources (all in widely varying degrees, depending upon locality), and certain building materials, such as gypsum wallboard, masonry and concrete. Radon progeny can attach themselves to various types of air particulates. Increased particulate levels, which can result from reduced ventilation, smoking, woodstoves and cooking, increase the potential levels of exposure to radiation from radon emissions.

Formaldehyde, which is present at some measureable level in most structures, is another emission substance with potential adverse health effects. At low concentrations, it induces irritation to eyes and mucous membranes in some individuals. Severity of symptoms increases with formaldehyde concentrations. Reductions in air flows within a structure in the presence of materials emitting formaldehyde gases increase the likelihood of adverse symptoms. Other effects of formaldehyde are suspected. In fact, after studying the relationship of formaldehyde exposure to incidence of cancer in rats, the Consumer Product Safety Commission voted on February 22, 1982, to ban the residential use of urea-formaldehyde foam insulation, thought to be a major source of formaldehyde in residences (BPA, 1982f). The ban was subsequently removed by the Federal Appellate Court in April 1983. Further appeals are uncertain at this time.

Particulates and other pollutants comprise an additional concern. Some particulates, such as those caused by smoking or the presence of asbestos in numerous household products, are potential hazards because of their inherent properties which have been linked to cancer and various respiratory conditions. (Asbestos use in building materials was banned in 1973, but it is still a potential source of air pollution in structures built prior to that date.)

These hazards are in addition to the fact that particulates are "vehicles" for radon progeny. Other pollutants of concern are carbon monoxide, nitrogen oxides, and hydrocarbons, which are generally caused by combustion (e.g., cooking, heating).

It should be noted that, at present, there is limited information relating to appropriate levels of each individual air pollutant, their direct effects on health, or synergistic (interactive) effects in the presence of other pollutants. Also, mitigating measures can be taken to reduce the effects of indoor air pollution due to conservation efforts. These measures include selection of materials with minimal potential for hazardous emissions, change in indoor activities (e.g., smoking), and installation of indoor-outdoor air exchange devices. BPA has planned for measures such as these in its proposed commercial buildings conservation program, and recently issued a finding of no significant impact of the program on the quality of the human environment (BPA, 1982e).

Outdoor impacts of conservation would include those associated with manufacture of materials used in conservation measures. Specifically, there would undoubtedly be a greater volume of wastes from manufacture of these materials. However, even if the manufacture occurred within the region, these impacts would likely be more than offset by the decrease in volume of wastes created by electric generation, which would most likely be thermal, due to the corresponding decrease in demand for electricity. Conservation could decrease the need for actual operation of large thermal plants, and therefore decrease the pollution levels due to plant operations. There is also the possibility that the demand for firm power could be reduced sufficiently to provide additional flexibility for non-power uses of hydro resources, such as increased availability of water for the protection and enhancement of fish migration.

2. Cogeneration

The nature and extent of environmental impacts from cogeneration facilities vary greatly from site to site, and are dependent on the types of fuel and technology used. Generally, impacts from cogeneration are very similar to those already resulting from a facility's basic system from which it derives its energy for industrial processing. For instance, incremental impacts to air quality of cogeneration fueled by oil will be similar to the impacts incurred from oil burning at the site for industrial production only.

The addition and use of cogeneration capabilities results in less waste heat and greater fuel efficiency than if industrial and electric generating processes were carried out separately. Cogenerating units, to the extent that they are used to produce electricity, could decrease the need for energy from large thermal electric plants, resulting in reduced environmental impacts on a regionwide scale. However, this would be accompanied by greater localized impacts in the immediate areas of the cogenerating units.

An estimated 80 percent of the potential for cogeneration in the Pacific Northwest is in the wood products industry. The most common types of fuel used in cogeneration facilities in the industry are hogged fuel (logging residues and mill scraps which are reduced to approximate chip size of 1/4" x 1" x 1") and sawdust, although other woodwastes (i.e., bark, wood pellets) are also used. The most significant air pollutants from combustion of wood are particulate matter, heavy organic materials, and fine particles of inorganic ash. Smaller particulates can have adverse effects on respiratory systems. Additional effects of particulates may include reduced visibility due to light scattering, corrosion and deterioration of nearby materials and buildings in

the presence of other pollutants, and adverse affects to vegetation. Other potential emissions from wood burning include sulfur dioxides, carbon monoxide, hydrocarbons, and nitrogen oxides.

In addition to air emissions resulting from wood burning, there may be some water pollution resulting from discharged waste water or from runoff from the site. This poses potential impacts to domestic water supplies, fisheries, or recreational areas. Disposal of solid wastes from wood fuel burning generally does not pose an environmental problem as long as proper wet handling methods are used and no toxic chemicals exist in the wood fuel or have been used in the combustion process.

While the environmental impacts of cogeneration are varied, their magnitude can be diminished by fuel selection (i.e., limits on the amounts of bark used in wood combustion), plant design, pollution control devices, and proper measures for disposing of liquid and solid wastes. In many cases, these measures are required to comply with Federal, State, and local environmental regulations.

3. Small Hydroelectric

The Pacific Northwest is rich in hydroelectric resources. Besides the Columbia River system, there are numerous other streams with significant potential for multiple applications. Most individual sites with large energy potential have already been developed. However, sites with smaller energy potential which had not been actively explored and considered earlier are now receiving considerable attention. FERC has approximately 400 applications pending for hydroelectric development in Idaho, Oregon, Montana, and Washington. FERC also has approximately 400 outstanding preliminary permits, indicating ongoing project feasibility studies, in the region (Northwest Power Planning Council, 1982a, page 12-1). Nationally, the small hydro potential could come from three sources: 15 percent from presently existing plants; 60 percent from installed power at existing nonhydro dams, and 25 percent from installed hydro power at new dams (Department of Energy, 1980, page 217). Regional development of small hydroelectric sites is expected to follow the same pattern.

Small hydroelectric plants are defined as having 15 MW or less capacity and fed by dams with heights no more than 65 feet, and impounding less than 500 acres. Some small hydro power projects use natural geographic features without the need for a dam.

The Federal Energy Regulatory Commission (FERC) maintains jurisdiction over the terms of licenses which govern the conditions under which projects can be operated. From 1965 to 1975 there were only a few applications to the FERC per year for permitting or licensing a hydroelectric project. Since then, the number each year has risen progressively and dramatically for projects all over the country. Washington and California probably are the States with the largest number of projects with applications pending before the FERC.

There are at least 17 Federal laws which may be applicable to a hydroelectric project. Fish, wildlife, and other environmental issues are addressed in the FERC review process. Local, State, and other Federal

agencies participate in the FERC process to ensure that their requirements are addressed. In addition to Federal laws, there are State and local regulations and requirements. These can range from local building codes and fire permits to regulations concerning water rights, environmental constraints, and provision of public access and recreation facilities.

Before BPA can acquire a small hydro plant, or purchase the power generated by the plant, certain policies and principles established by the Regional Act must be met. These include the stipulation that a project must be cost-effective, including environmental costs, and that the project must meet fish and wildlife requirements.

Table IV-15 contains information on the environmental concerns associated with a small hydroelectric plant. As compared to other sources of electricity, the environmental effects of individual small hydro plants are minor. However, the collective impacts of small hydro development throughout a river basin could be harmful to migratory fish. BPA will be working with the Regional Council to develop criteria and methods for assessing potential cumulative effects of hydroelectric development on fish and wildlife. The study will also develop a method for incorporating these assessments into federal processes for review, authorization, or other support of hydroelectric development. The consequences of small hydro development may include effects on aquatic and semiaquatic organisms; releases of impounded chemicals, conflicts of land and water use, and dam safety and potential effects of dam failure.

4. Nuclear System

Table IV-16 contains information on the major pollutants associated with a 1,000 MW boiling water nuclear reactor. This table presents information on environmental impacts on a system basis, tracing the process from mining of ore through the generation of electricity. The material is presented in separate steps because of the complexity of the information involved. The resources used, residuals and products are presented per trillion Btu's of energy produced. This allows cross comparisons between energy system tables (Tables IV-15, IV-16, and IV-17). For example, the air pollutants resulting from mining a quantity of western coal sufficient to produce the electrical equivalent of a trillion BTU's of energy in a coal fired system can be compared with the air pollutants generated by mining a amount of uranium sufficient to produce an equivalent measure of energy in a nuclear generating facility.

To understand the cumulative effects of a 1,000 MW nuclear energy system, the annual energy production of the representative plant is assumed to be 21.7 trillion Btu/year, given a 70 percent capacity factor and a 3.5 percent transmission loss factor. Therefore, the individual effects per trillion BTU's of energy produced, such as air pollutants, listed in Table 16, can be multiplied by 21.7 to determine the cumulative impacts of a 1,000 MW nuclear system. The following discussion summarizes by step the data presented in Table IV-15 on the environmental impacts of a light water nuclear energy system from mining to electricity generation.

TABLE IV-15. SMALL HYDROELECTRIC PLANT

REFERENCE ENERGY SYSTEM	FACILITY OPERATING PARAMETERS
Small hydroelectric plants are those with less than 15 MWe of capacity and usually fed by a dam with height not more than 65 ft. Impounding is generally less than 500 acres. Components of a typical system (not an exhaustive listing) include the dam, penstock, hydraulic turbine, generator(s) transformer, and other miscellaneous structures and equipment.	Size: 4 MWe Annual Capacity Factor: 0.35 for new plants, 0.37 for retrofits Annual Energy Production: 0.04×10^{12} Btu Efficiency: 90% Lifetime: 50 yr

RESOURCES USED	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Water	0.792 × 10 ⁶ acre-ft	0.977 × 10 ¹² l	19.8 × 10 ⁶ acre-ft	Kinetic energy of falling or flowing water
<u>Energy Requirements</u>				
Auxiliary		Not Determined		
	Total Usage			
<u>Construction Materials</u>		Not Determined		Typical system components are listed in Reference Energy System description
<u>Land</u>		Not Determined		
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance		↓		

COSTS	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility*</u>		(1977 \$)	
Construction	$\$7.52 \times 10^6$ total	$\$188 \times 10^6$ total	
		(1972 \$)	
Operation and maintenance	$\$0.054 \times 10^6/\text{yr}$	$\$1.35 \times 10^6/\text{yr}$	
<u>Environmental Controls</u>			
Upstream fish passage facilities can cost between $\$20 \times 10^3$ to $\$98 \times 10^3$ /m of elevation			Hydroelectric systems can have water quality and ecological impacts
*Costs are for "installed hydro-power at new dams."			

TABLE IV-15 cont. **SMALL HYDROELECTRIC PLANT**

ENVIRONMENTAL RESIDUALS				
	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Water Pollutants</u>				
Thermal stratification in the reservoir can lead to a lowering of dissolved oxygen levels and elevated concentration of ammonia, hydrogen sulfide, iron, and manganese; shoreline erosion may result in increased turbidity				
<u>Thermal Discharge</u>				
Thermal stratification in the reservoir can result in discharged water being warmer in winter and cooler in summer than ambient river water				

PRODUCTS				
	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electricity	0.012 × 10 ⁹ kWh	0.012 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH				
Not Determined				

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-16 STEP 1

OPEN PIT URANIUM MINING

REFERENCE ENERGY SYSTEM

Open pit mining is conducted when the ore body lies under relatively friable material at depths to 120 m. The components of the mining operation include onsite support facilities such as offices and warehouses, mine water pumped into local surface drainage or holding ponds, and mine spoils and ore storage areas.

FACILITY OPERATING PARAMETERS

Size:	528 × 10 ³ tons/yr (average ore grade 0.2% U ₃ O ₈)
Annual Capacity Factor:	80%
Annual Energy Production:	115 × 10 ¹² Btu
Efficiency:	80% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Electricity	1.32 × 10 ³ MWh	1.32 × 10 ³ MWh	11.5 MWh	
Diesel fuel and lubricants	1.46 × 10 ⁶ gal	5.53 × 10 ⁶ l	12.7 × 10 ³ gal	
<u>Processing Materials</u>				
Explosives		Not Determined		
<u>Water</u>				
Mine water from dewatering	2.00 × 10 ³ acre-ft	2.46 × 10 ⁹ l	17.3 acre-ft	
Sprays for dust control		Not Determined		
	Total Usage			
<u>Construction Materials</u>				
Concrete	16 tons	15 tonnes	0.14 ton	
Total steel and castings	3.73 × 10 ³ tons	3.38 × 10 ³ tonnes	32.40 tons	
Copper, brass, and bronze	46 tons	42 tonnes	0.40 ton	
Aluminum and castings	22 tons	20 tonnes	0.19 ton	
Manganese	17 tons	16 tonnes	0.15 ton	
Chromium	8 tons	7 tonnes	0.07 ton	
Nickel	0.23 ton	0.21 tonne	0.002 ton	
Cast iron	155 tons	141 tonnes	1.35 tons	
<u>Land</u>	300 acres	120 ha	2.6 acres	
<u>Personnel</u>				
Construction (4 yr)	115 workers		1 worker	
Operation and maintenance	400 workers		3.5 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
	(1978 \$)		
Construction (4 yr)	\$59.4 × 10 ⁶ total	\$0.517 × 10 ⁶ total	
Operation and maintenance	\$22.8 × 10 ⁶ /yr	\$0.198 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Diversion of surface waters	Not Determined		
Water spraying for dust control	↓		
Revegetation			

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	31 tons	28 tonnes	0.27 ton	
Sulfur dioxide	49 tons	45 tonnes	0.43 ton	
Oxides of nitrogen	29 tons	26 tonnes	0.25 ton	
Hydrocarbons	2.3 tons	2.1 tonnes	0.02 ton	
Carbon monoxide	0.12 ton	0.10 tonne	0.001 ton	
Radon and radon daughters	3.37 × 10 ³ Ci	3.37 × 10 ³ Ci	29.3 Ci	
<u>Water Pollutants</u>				
Suspended solids		Not Determined		
Dissolved solids		↓		
Trace elements				
<u>Solid Wastes</u>				
Overburden moved	16 × 10 ⁶ tons	15 × 10 ⁶ tonnes	0.14 × 10 ⁶ tons	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Uranium ore	0.53 × 10 ⁶ tons	0.48 × 10 ⁶ tonnes	4.6 × 10 ³ tons	
U ₃ O ₈ concentrate	1.06 × 10 ³ tons	960 tonnes	9.2 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-16, STEP 2.

URANIUM MILLING

REFERENCE ENERGY SYSTEM

The model is a uranium mill described by the Nuclear Regulatory Commission in the Final Generic Environmental Impact Statement on Uranium Milling, NUREG-0706, Vol. I-III, September 1980. Tailings control and disposal includes retention basin, clay liner, evaporation pond, in situ solids filtration, and earth cover.

FACILITY OPERATING PARAMETERS

Size: 635 tons/yr uranium concentrate (yellowcake at 90% U_3O_8)

Annual Capacity Factor: 85%

Annual Energy Production: 68.3×10^{12} Btu

Efficiency: 93% (recovery)

Lifetime: 15 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium ore (0.1% uranium)	620 × 10 ³ tons	560 × 10 ³ tonnes	9.1 × 10 ³ tons	
<u>Energy^a</u>				
Electrical	10.8 × 10 ³ MWh	10.8 × 10 ³ MWh	158 MWh	
Natural gas (process heat)	274 × 10 ⁶ scf	7.76 × 10 ⁶ m ³	4.0 × 10 ⁶ scf	
<u>Processing Materials</u>				
Sulfuric acid	28 × 10 ³ tons	25 × 10 ³ tonnes	400 tons	
Sodium chlorite	860 tons	780 tonnes	13 tons	
Ammonium	680 tons	610 tonnes	10 tons	
Flocculent	37 tons	34 tonnes	0.54 ton	
Amine	9 tons	8 tonnes	0.1 ton	
Alcohol	25 tons	22 tonnes	0.4 ton	
Kerosene	280 tons	250 tonnes	4 tons	
Iron	150 tons	140 tonnes	2.2 tons	
<u>Water</u>				
Process water	320 acre-ft	390 × 10 ⁶ l	4.7 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	250 × 10 ³ ft ³	7.0 × 10 ³ m ³	3.7 × 10 ³ ft ³	
Steel	1.7 × 10 ³ tons	1.6 × 10 ³ tonnes	25 tons	
Copper and aluminum	52 tons	47 tonnes	0.76 ton	
Wood	18 tons	16 tonnes	0.26 ton	
Plastics	18 tons	16 tonnes	0.26 ton	
<u>Land</u>				
Mill operations	120 acres	50 ha	1.8 acres	
Tailings	250 acres	100 ha	3.7 acres	
Uncommitted	370 acres	150 ha	5.4 acres	
Total	740 acres	300 ha	10.9 acres	
<u>Personnel</u>				
Construction (5 yr)	120 workers		1.76 workers	
Operation and maintenance	160 workers		2.34 workers	

(Continued on next page)

TABLE IV-16. STEP 2 cont.

URANIUM MILLING

COSTS	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction (5 yr)	\$37.1 × 10 ⁶ total	\$0.54 × 10 ⁶ total	
Operation and maintenance	\$ 8.5 × 10 ⁶ /yr	\$0.13 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
<u>Ore crushing/handling</u>			
wet scrubbers	\$155 × 10 ³ total \$18.8 × 10 ³ /yr	\$2.3 × 10 ³ total \$0.275 × 10 ³ /yr	Total capital costs Operating costs per year
<u>Yellowcake drying</u>			
wet scrubbers	\$50.4 × 10 ³ total \$6.2 × 10 ³ /yr	\$0.7 × 10 ³ total \$0.091 × 10 ³ /yr	Total capital costs Operating costs per year
Tailings control and disposal	\$13.7 × 10 ⁶ total	\$0.200 × 10 ⁶ total	Includes capital and total operating costs over lifetime

ENVIRONMENTAL RESIDUALS

UNRECOVERED RESIDUALS				
	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Air Pollutants</u>				
Particulates	370 tons	340 tonnes	5.4 tons	
Sulfur dioxide	0.34 ton	0.31 tonnes	5.0 × 10 ⁻³ ton	
Oxides of nitrogen	28 tons	25 tonnes	0.41 tons	
Kerosene	24 tons	22 tonnes	0.35 ton	
Uranium-238, Uranium-234	0.160 Ci	0.160 Ci	2.3 × 10 ⁻³ Ci	
Thorium-230	0.122 Ci	0.122 Ci	1.8 × 10 ⁻³ Ci	
Radon	4.5 × 10 ³ Ci	4.5 × 10 ³ Ci	66 Ci	
<u>Water Pollutants</u>				
Water discharged	326 acre-ft	402 × 10 ⁶ l	4.8 acre-ft	
• Sulfate	13 × 10 ³ tons	12.1 × 10 ³ tonnes	190 tons	
• Iron	440 tons	400 tonnes	6.5 tons	
• Manganese	22 tons	20 tonnes	0.32 ton	
• Selenium	0.88 ton	0.80 tonne	0.01 ton	
Uranium-natural	1.3 Ci	1.3 Ci	19 × 10 ⁻³ Ci	
Radium-226	0.1 Ci	0.1 Ci	1.4 × 10 ⁻³ Ci	
Thorium-230	36 Ci	36 Ci	0.53 Ci	
<u>Solid Wastes</u>				
Tailings	610 × 10 ³ tons	560 × 10 ³ tonnes	9.0 × 10 ³ tons	
Uranium-natural	21.8 Ci	21.8 Ci	0.32 Ci	
Radium-226	156 Ci	156 Ci	2.3 Ci	
Thorium-230	156 Ci	156 Ci	2.3 Ci	
Lead-210, polonium-210, bismuth-210	0.3 Ci	0.3 Ci	4 × 10 ⁻³ Ci	
<u>Thermal Discharge</u>				
Process heat to air	280 × 10 ⁹ Btu	300 × 10 ¹² J	4.1 × 10 ⁹ Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Yellowcake (90% U ₃ O ₈)	635 tons	580 tonnes	9.3 tons	
<u>Recoverables/Recyclables</u>				
30% of the tailings liquid	135 acre-ft.	166 × 10 ⁶ l	1.99 acre-ft	

TABLE IV-16, STEP 2 cont.

URANIUM MILLING

OCCUPATIONAL SAFETY AND HEALTH^b

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	0.47	0.007	1977 Data ↓
<u>Injuries</u>	34	0.50	

^aU.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle, WASH-1248, 1974.

^bOak Ridge National Laboratory, An Integrated Assessment of the Impacts Associated with Uranium Mining and Milling, ORNL/TM-6677, July 1979.

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c,

TABLE IV-16,
STEP 3.

URANIUM HEXAFLUORIDE CONVERSION

REFERENCE ENERGY SYSTEM

Conversion of "yellowcake" uranium concentrate into a volatile uranium hexafluoride compound for enrichment by the gaseous diffusion process; uranium hexafluoride conversion by either the dry hydrofluor process or the wet solvent exchange process; offgas treatment to minimize airborne residuals; neutralization and impoundment of liquid wastes.

FACILITY OPERATING PARAMETERS

Size:	5.5×10^3 tons/yr (actual output)
Annual Capacity Factor:	80%
Annual Energy Production:	655×10^{12} Btu
Efficiency:	100% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Yellowcake (75% U ₃ O ₈)	7.34 × 10 ³ tons	6.66 × 10 ³ tonnes	11.2 tons	
U ₃ O ₈ (purified)	5.5 × 10 ³ tons	5.0 × 10 ³ tonnes	8.4 tons	
<u>Energy</u>				
Electricity	46 × 10 ³ MWh	46 × 10 ³ MWh	71 MWh	
Natural gas	540 × 10 ⁶ scf	15 × 10 ⁶ m ³	0.83 × 10 ⁶ scf	
<u>Processing Materials</u>				
Nitric acid	Not Determined ↓			
Tributylphosphate				
Hexane				
Anhydrous ammonia				
Hydrofluoric acid				
Fluorine				
<u>Water</u>				
Discharged to air	0.28 × 10 ³ acre-ft	0.34 × 10 ⁹ l	0.42 acre-ft	
Discharged to water	1.92 × 10 ³ acre-ft	2.38 × 10 ⁹ l	2.94 acre-ft	
Total	2.20 × 10 ³ acre-ft	2.72 × 10 ⁹ l	3.36 acre-ft	
Total Usage				
<u>Construction Materials</u>				
Concrete	259 × 10 ³ tons	235 × 10 ³ tonnes	395 tons	
Steel and castings	8.19 × 10 ³ tons	7.43 × 10 ³ tonnes	12.5 tons	
Copper, brass, and bronze	120 tons	110 tonnes	0.19 ton	
Aluminum and castings	39 tons	36 tonnes	0.06 ton	
Manganese	39 tons	36 tonnes	0.06 ton	
Chromium	39 tons	36 tonnes	0.06 ton	
Nickel	7 tons	6 tonnes	0.01 ton	
Cast iron	98 tons	89 tonnes	0.15 ton	
Pumps and drivers	7 × 10 ³ hp	5 × 10 ⁶ W	0.01 × 10 ³ hp	
Heat exchangers	30 × 10 ³ ft ³	3 × 10 ³ m ²	0.05 × 10 ³ ft ²	
Nonnuclear pressure vessel	220 tons	200 tonnes	0.33 ton	
<u>Land</u>				
	65 acres	27 ha	0.10 acre	
<u>Personnel</u>				
Construction (3 yr)	200 workers		0.3 worker	
Operation and maintenance	300 workers		0.4 worker	

TABLE IV-16.
STEP 3 cont.

URANIUM HEXAFLUORIDE CONVERSION

COSTS			
Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
	(1978 \$)		
Construction (3 yr)	\$55.2 × 10 ⁶ total	\$0.0843 × 10 ⁶ total	
Operation and maintenance	\$16 × 10 ⁶ /yr	\$0.024 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Fluorine scrubbers	Not Determined ↓		
Raffinate/waste ponds			
Offgas filters/traps			

ENVIRONMENTAL RESIDUALS				
	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur dioxide	850 tons	770 tonnes	1.3 tons	10 CFR 20 specifies allowable levels
Oxides of nitrogen	300 tons	270 tonnes	0.46 ton	
Hydrocarbons	30 tons	20 tonnes	0.04 ton	
Carbon monoxide	7 tons	6 tonnes	0.01 ton	
Fluoride	3.3 tons	3.0 tonnes	0.005 ton	
Uranium	4.1 × 10 ⁻³ Ci	4.1 × 10 ⁻³ Ci	6.2 × 10 ⁻⁶ Ci	
Radon and radon daughters		Not Determined		
<u>Water Pollutants</u>				
Fluoride	790 tons	710 tonnes	1.2 tons	10 CFR 20 specifies allowable levels
Sulfate	140 tons	120 tonnes	0.21 ton	
Nitrate	7 tons	6 tonnes	0.01 ton	
Chloride	7 tons	6 tonnes	0.01 ton	
Sodium ⁺	105 tons	95 tonnes	0.16 ton	
Ammonium	50 tons	40 tonnes	0.07 ton	
Iron	1.3 tons	1.2 tonnes	0.002 ton	
Radium-226	92 × 10 ⁻³ Ci	92 × 10 ⁻³ Ci	0.14 × 10 ⁻³ Ci	
Thorium-230	41 × 10 ⁻³ Ci	41 × 10 ⁻³ Ci	0.063 × 10 ⁻³ Ci	
Uranium	1.2 Ci	1.2 Ci	1.8 × 10 ⁻³ Ci	
<u>Solid Wastes</u>				
Solid chemical effluents (nonvolatile ash containing iron, calcium, magnesium, copper, fluoride)	1.2 × 10 ³ tons	1.1 × 10 ³ tonnes	1.8 tons	10 CFR 20 specifies allowable levels
Low and intermediate level radioactive (buried)	24 Ci	24 Ci	36 × 10 ⁻³ Ci	
<u>Thermal Discharge</u>				
Heat discharged to air	0.54 × 10 ¹² Btu	0.57 × 10 ¹⁵ J	0.83 × 10 ⁹ Btu	

PRODUCTS				
	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
	<u>Primary</u>			
Uranium hexafluoride	5.5 × 10 ³ tons	5.0 × 10 ³ tonnes	8.4 tons	

OCCUPATIONAL SAFETY AND HEALTH	
Not Determined	

SOURCE: Technology Characterizations Environmental Information
Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-16. URANIUM ENRICHMENT GASEOUS DIFFUSION
STEP 4.

REFERENCE ENERGY SYSTEM

Gaseous diffusion enrichment plant using porous barriers and compressors arranged in series to produce uranium hexafluoride enriched to 4% uranium-235; onsite support facilities; tails storage; settling/neutralization ponds; waste burial grounds; feed vaporization and product recovery systems; steam plant.

FACILITY OPERATING PARAMETERS

Size: 12×10^3 tons/yr (enriched uranium-235 as uranium hexafluoride; tails assay 0.2% uranium)
Annual Capacity Factor: 80%
Annual Energy Production: 2190×10^{12} Btu
Efficiency: 65.4% (recovery efficiency)
Lifetime: 20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium hexafluoride (unenriched)	18 × 10 ³ tons	17 × 10 ³ tonnes	8.4 tons	
<u>Energy</u>				
Electricity	28 × 10 ⁶ MWh	28 × 10 ⁶ MWh	13 × 10 ³ MWh	
<u>Water</u>				
Discharged to air	23 × 10 ³ acre-ft	29 × 10 ⁹ l	11 acre-ft	
Discharged to water bodies (at diffusion plant)	1.8 × 10 ³ acre-ft	22 × 10 ⁹ l	0.8 acre-ft	
Discharged to water bodies (at power plant)	3.07 × 10 ⁶ acre-ft	3.8 × 10 ¹² l	1.4 × 10 ³ acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	1670 × 10 ³ tons	1510 × 10 ³ tonnes	760 tons	
Total steel and castings	723 × 10 ³ tons	656 × 10 ³ tonnes	330 tons	
Copper, brass, and bronze	25.6 × 10 ³ tons	23.3 × 10 ³ tonnes	11.7 tons	
Aluminum and castings	16 × 10 ³ tons	15 × 10 ³ tonnes	7.5 tons	
Manganese	3.9 × 10 ³ tons	3.6 × 10 ³ tonnes	1.8 tons	
Chromium	5.0 × 10 ³ tons	4.6 × 10 ³ tonnes	2.3 tons	
Nickel	0.90 × 10 ³ tons	0.82 × 10 ³ tonnes	0.41 ton	
Cast iron	58.0 × 10 ³ tons	52.7 × 10 ³ tonnes	26.5 tons	
Steam turbogenerators	520 MWe	520 MWe	0.24 MWe	
Pumps and drivers	590 × 10 ³ hp	440 × 10 ⁶ W	0.27 × 10 ³ hp	
Axial compressor	8300 × 10 ³ hp	6200 × 10 ⁶ W	3.8 × 10 ³ hp	
Centrifuge compressors and drivers	22 tons	20 tonnes	0.01 ton	
Heat exchangers	7.9 × 10 ⁶ ft ²	730 × 10 ³ m ²	3.6 × 10 ³ ft ²	
<u>Land</u>				
Not Determined				
<u>Personnel</u>				
Construction (8 yr)	6.1 × 10 ³ workers		2.8 workers	
Operation and maintenance	2.2 × 10 ³ workers		1.0 worker	

TABLE IV-16. URANIUM ENRICHMENT GASEOUS DIFFUSION
STEP 4 cont.

COSTS	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
	(1978 \$)		
Construction (8 yr)	\$11.5 × 10 ⁹ total	\$5.24 × 10 ⁶ total	
Operation and maintenance	\$770 × 10 ⁶ /yr	\$0.35 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Cooling towers	Not Determined ↓		
Liquid waste systems			
Neutralization pond			
Filters			
Fluorine scrubber			

ENVIRONMENTAL RESIDUALS	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	113 × 10 ³ tons	103 × 10 ³ tonnes	51.8 tons	
Sulfur dioxide	431 × 10 ³ tons	392 × 10 ³ tonnes	197 tons	
Oxides of nitrogen	113 × 10 ³ tons	103 × 10 ³ tonnes	51.8 tons	
Hydrocarbons	1.1 × 10 ³ tons	1.0 × 10 ³ tonnes	0.5 ton	
Carbon monoxide	2.8 × 10 ³ tons	2.6 × 10 ³ tonnes	1.3 tons	
Fluoride	0.044 × 10 ³ tons	0.04 × 10 ³ tonnes	0.02 ton	
Uranium	0.18 Ci	0.18 Ci	83 × 10 ⁻⁶ Ci	
Technetium-99	0.74 Ci	0.74 Ci	0.34 × 10 ⁻³ Ci	
Ruthenium-106	0.010 Ci	0.010 Ci	4.6 × 10 ⁻⁶ Ci	
<u>Water Pollutants</u>				
Calcium	700 tons	600 tonnes	0.3 ton	
Chloride	900 tons	800 tonnes	0.4 ton	
Sodium ⁺	900 tons	800 tonnes	0.4 ton	
Sulfate	700 tons	600 tonnes	0.3 ton	
Iron	44 tons	40 tonnes	0.02 ton	
Nitrate	260 tons	240 tonnes	0.12 ton	
Uranium	1.8 Ci	1.8 Ci	0.83 × 10 ⁻³ Ci	
Technetium-99	9.6 Ci	9.6 Ci	4.4 × 10 ⁻³ Ci	
<u>Solid Wastes</u>				
Equipment components	Not Determined ↓			
Sludges				
<u>Thermal Discharge</u>				
Heat discharged to water	226 × 10 ¹² Btu	238 × 10 ¹⁵ J	103 × 10 ⁹ Btu	
Heat discharged to air	68 × 10 ¹² Btu	72 × 10 ¹⁵ J	31 × 10 ⁹ Btu	
<u>Noise Pollution</u>				
In-plant	Not Determined ↓			
Cooling tower				

PRODUCTS	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Enriched uranium-235 in uranium hexafluoride	12.0 × 10 ³ tons	10.9 × 10 ³ tonnes	5.49 tons	
<u>Byproducts</u>				
Uranium-235 in tails	22 tons	20 tonnes	0.01 ton	Tails 0.2% uranium

OCCUPATIONAL SAFETY AND HEALTH
Not Determined

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-16. STEP 5.

FUEL FABRICATION PLANT**REFERENCE ENERGY SYSTEM**

Fuel fabrication is accomplished by chemical conversion of uranium hexafluoride to uranium dioxide and mechanical processing including pellet production and fuel element fabrication loaded in zircalloy or stainless steel tubes, fitted with end caps, and welded.

FACILITY OPERATING PARAMETERS

Size: 990 tons/yr
 Annual Capacity Factor: 80%
 Annual Energy Production: 619×10^{12} Btu
 Efficiency: 100% (uranium-235 output vs. uranium-235 input)
 Lifetime: 20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium-235 enriched in uranium hexafluoride	3.40 × 10 ³ tons	3.08 × 10 ³ tonnes	5.49 tons	
<u>Energy</u>				
Electricity	44 × 10 ³ MWh	44 × 10 ³ MWh	71 MWh	
Natural gas	93 × 10 ⁶ scf	2.6 × 10 ⁶ m ³	0.15 × 10 ⁶ scf	
<u>Processing Materials</u>				
Aqueous ammonia	Not Determined ↓			
Nitric acid (70%)				
Sodium hydroxide (50%)				
Sulfuric acid (70%)				
<u>Water</u>				
Discharged to water	410 acre-ft	510 × 10 ⁶ l	0.67 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	46.2 × 10 ³ - 275 × 10 ³ tons	42.0 × 10 ³ - 250 × 10 ³ tonnes	74.70-444.0 tons	
Total steel and castings	7.43 × 10 ³ - 27.8 × 10 ³ tons	6.74 × 10 ³ - 25.3 × 10 ³ tonnes	12.00-45.00 tons	
Copper, brass, and bronze	360 - 3.22 × 10 ³ tons	330 - 2.92 × 10 ³ tonnes	0.59-5.20 tons	
Aluminum and castings	170-885 tons	150-800 tonnes	0.27-1.43 tons	
Manganese	50-130 tons	40-120 tonnes	0.08-0.21 ton	
Chromium	62-93 tons	56-84 tonnes	0.10-0.15 ton	
Nickel	12-18 tons	11-17 tonnes	0.02-0.03 ton	
Cast iron	300-560 tons	280-510 tonnes	0.49-0.90 ton	
Steam turbines	0 - 6.2 × 10 ³ hp	0 - 4.6 × 10 ⁶ W	0-10 hp	
Pumps and drivers	6.2 × 10 ³ - 25 × 10 ³ hp	4.6 × 10 ⁶ - 18 × 10 ⁶ W	10-40 hp	
Heat exchangers	0 - 18 × 10 ³ ft ²	0 - 1.7 × 10 ³ m ²	0-30 ft ²	
<u>Land</u>	7.4 acres	3.0 ha	0.012 acre	
<u>Personnel</u>				
Construction (2-3 yr)	400-2.1 × 10 ³ workers		0.7-3.4 workers	
Operation and maintenance	990-2.1 × 10 ³ workers		1.6-3.4 workers	

TABLE IV-16, STEP 5 cont. **FUEL FABRICATION PLANT**

COSTS			
	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>	(1978 \$)		
Construction (2-3 yr)	$\$155 \times 10^6 - 496 \times 10^6$ total	$\$0.250 \times 10^6 - 0.801 \times 10^6$ total	
Operation and maintenance	$\$111 \times 10^6 - 161 \times 10^6$ /yr	$\$0.180 \times 10^6 - 0.260 \times 10^6$ /yr	
<u>Environmental Controls</u>			
High-efficiency particulate aerosol filter system	Not Determined ↓		
Scrubbers and dryers			
Waste lagoons			
Sanitary waste system			

ENVIRONMENTAL RESIDUALS			
	<u>Quantities Released</u>		
	<u>Reference Energy System Annual Levels</u>		<u>Per 10¹² Btu Energy Produced</u>
	<u>English Units</u>	<u>Metric Units</u>	<u>Remarks</u>
<u>Air Pollutants</u>			
Sulfur dioxide	681 tons	618 tonnes	1.10 tons
Oxides of nitrogen	170 tons	160 tonnes	0.28 ton
Carbon monoxide	6.2 tons	5.6 tonnes	0.01 ton
Uranium	5.1×10^{-3} Ci	5.1×10^{-3} Ci	8.3×10^{-6} Ci
<u>Water Pollutants</u>			
Nitrogen as ammonia	280 tons	260 tonnes	0.46 ton
Nitrogen as nitrate	681 tons	618 tonnes	1.10 tons
Fluoride	120 tons	110 tonnes	0.19 ton
Uranium	0.51 Ci	0.51 Ci	0.83×10^{-3} Ci
Thorium-234	0.26 Ci	0.26 Ci	0.42×10^{-3} Ci
<u>Solid Wastes</u>			
Calcium fluoride	743 tons	674 tonnes	1.20 tons
Ammonia		Not Determined ↓	
Fluorine			
Sulfur oxide			
Nitrate			
Uranium (buried)	5.9 Ci	5.9 Ci	9.6×10^{-3} Ci
<u>Thermal Discharge</u>			
Heat dissipated	200×10^9 Btu	300×10^{12} J	0.4×10^9 Btu

PRODUCTS			
	<u>Quantities Produced</u>		
	<u>Reference Energy System Annual Production</u>		<u>Per 10¹² Btu Energy Produced</u>
	<u>English Units</u>	<u>Metric Units</u>	<u>Remarks</u>
<u>Primary</u>			
Uranium (uranium dioxide) fuel elements	990 tons	900 tonnes	1.6 tons

OCCUPATIONAL SAFETY AND HEALTH			
Not Determined			

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-16. **BOILING WATER REACTOR NUCLEAR POWER PLANT**
STEP 6.

REFERENCE ENERGY SYSTEM	FACILITY OPERATING PARAMETERS
The General Electric Company's standardized BWR/6 reactor with the Mark III containment design. Natural draft cooling towers.	Size: 1000 MWe Annual Capacity Factor: 70% Annual Energy Production: 21×10^{12} Btu Efficiency: 33% Lifetime: 30 yr

RESOURCES USED	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium fuel (3.0% uranium-235 enriched)	34 tons	31 tonnes	1.6 tons	One-fourth of core annually
<u>Processing Materials</u>				
<u>Water</u>				
Make-up water for cooling towers and miscellaneous plant services	25 × 10 ³ acre-ft	30 × 10 ⁹ l	1.2 × 10 ³ acre-ft	
	Total Usage			
<u>Construction Materials</u>				
Concrete	4.5 × 10 ⁶ ft ³	130 × 10 ³ m ³	210 × 10 ³ ft ³	
Reinforcing steel	17 × 10 ³ tons	15 × 10 ³ tonnes	810 tons	
Structural steel	8.7 × 10 ³ tons	7.9 × 10 ³ tonnes	420 tons	
			Per 10 ¹² Btu Energy Capacity	
<u>Land*</u>				
Site land requirements	1100 ± 900 acres	450 ± 360 ha	21 ± 17 acres	
Transmission route	1800 ± 2200 acres	730 ± 890 ha	34 ± 42 acres	
Disrupted land surface (site)	350 ± 610 acres	140 ± 250 ha	6.7 ± 3.0 acres	
Committed land	130 ± 100 acres	53 ± 40 ha	2.5 ± 1.9 acres	
<u>Personnel</u>				
Construction (9 yr)	480 workers		22.8 workers	9.5 × 10 ⁶ man-hour for craft labor; average work force of 3000
Operation and maintenance		Not Determined		
*For two 1250-MWe units with cooling towers.				

*For two 1250-MWe units with cooling towers.

COSTS	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
	(1981 \$)		
<u>Facility</u>			
Construction (9 yr) (with interest during construction)	$\$1.0 \times 10^9$ total	$\$48 \times 10^6$ total	
Operation and maintenance	$\$77 \times 10^6$ /yr	$\$0.81 \times 10^6$ /yr	
<u>Environmental Controls</u>			
	Not Determined		

TABLE IV-16.
STEP 8 cont.

BOILING WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS				
	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Gaseous radioactive effluents				
• Noble gases	11.3 × 10 ³ Ci	11.3 × 10 ³ Ci	540 Ci	
• Tritium	110 Ci	110 Ci	5.2 Ci	
• Carbon-14	6.8 Ci	6.8 Ci	0.32 Ci	
• Iodine-131 (elemental)	64 × 10 ⁻³ Ci	64 × 10 ⁻³ Ci	3.0 × 10 ⁻³ Ci	
• Iodine-131 (nonelemental)	140 × 10 ⁻³ Ci	140 × 10 ⁻³ Ci	6.6 × 10 ⁻³ Ci	
Combustion emissions				
• Sulfur oxides	20 tons	18 tonnes	0.95 ton	
• Carbon monoxide	98 tons	89 tonnes	4.7 tons	
• Nitrogen oxides	70 tons	63 tonnes	3.3 tons	
<u>Water Pollutants</u>				
Liquid radioactive effluents				
• Tritium	14 Ci	14 Ci	0.67 Ci	
• Activation and fission products	0.1 Ci	0.1 Ci	5 × 10 ⁻³ Ci	
Dissolved solids				
• Sulfates	23 tons	21 tonnes	1.1 tons	
• Chlorine	0.9 ton	0.8 tonne	0.04 ton	
• Sodium	11 tons	10 tonnes	0.53 ton	
• Other	5.8 tons	5.3 tonnes	0.28 ton	
<u>Solid Wastes</u>				
Low-level solid radioactive wastes				
• Wet material embedded in concrete	19 × 10 ³ ft ³	530 m ³	900 ft ³	
• Dry material in drums	3.3 × 10 ³ ft ³	94 m ³	160 ft ³	
Water filtration waste products				
• Aluminum hydroxide	10 tons	9.1 tonnes	0.48 ton	
• Settled solids	8 tons	7.3 tonnes	0.38 ton	
<u>Thermal Discharge</u>				
Heat dissipated	61 × 10 ¹² Btu	64 × 10 ¹⁵ J	2.9 × 10 ¹² Btu	
<u>Noise Pollution</u>				
		Negligible		

PRODUCTS				
	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Electric power	6.13 × 10 ⁹ kWh	6.13 × 10 ⁹ kWh	2.93 × 10 ⁹ kWh	
<u>Byproducts</u>				
		Not Determined		
<u>Recoverables/Recyclables</u>				
Spent nuclear fuel containing				
• Uranium-235 nuclear fuel				
— Mass	616 lb	280 kg	29.3 lb	
— Energy equivalent	4.3 × 10 ⁹ kWh (14.7 × 10 ²¹ Btu)	4.3 × 10 ⁹ kWh (15.5 × 10 ²⁴ J)	0.21 × 10 ⁹ kWh (0.7 × 10 ²¹ Btu)	
• Fissile plutonium nuclear fuel				
— Mass	396 lb	780 kg	18.8 lb	
— Energy equivalent	3.4 × 10 ⁹ kWh (10.5 × 10 ²¹ Btu)	3.4 × 10 ⁹ kWh (11.1 × 10 ²⁴ J)	1.6 × 10 ⁹ kWh = 0.5 × 10 ²¹ Btu (0.5 × 10 ²¹ Btu)	
• Isotopes for medical and industrial applications		Not Determined		

(Continued on next page)

TABLE IV-16. **BOILING WATER REACTOR NUCLEAR POWER PLANT**
 STEP 6 cont.

OCCUPATIONAL SAFETY AND HEALTH			
	<u>Reference Energy System Annual</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Deaths</u>	0.0	0.0	
<u>Injuries</u>			
Number	0.51-3.0	0.02-0.14	
Total lost days	14-91	0.67-4.33	
<u>Occupational Radiation Exposure</u>	1.1 × 10 ³ man-rem	53 man-rem	Average collective dose

SOURCE: Technology Characterizations Environmental Information
 Handbook, U.S. Department of Energy, June 1981c.

Surface mining of uranium (Table IV-16, Step 1) has a number of adverse effects on the environment; however, mining impacts are relatively minimal. The mining necessary to supply a 1,000 MW nuclear plant disturbs 56.4 acres per year. Air residuals originate from the diesel powered equipment used in mining and from wind erosion, although dust suppression practices, reclamation, and revegetation of mined areas can reduce the particulates generated by wind erosion. Water pollution occurs from suspended solids produced by runoff from piles of overburden and the mined surfaces. Radiation hazards are not a problem in the low grade open-pit mines located in the United States. The residuals from transportation are negligible. There is a risk from mining accidents.

At the mine site, the milling operation (Table IV-16, Step 2) extracts uranium from the ore and concentrates it, using chemical and mechanical processes, into a semi-refined product called "yellowcake." These processes produce fumes, vapors, and dusts of a chemical and radiological nature. The processes use water and can affect the quantity and quality of water supplies, particularly ground water. Heat from the processes must be dissipated into the environment. Problems of radiological waste disposal (tailings) exist and there is risk from accidents.

While almost all of the current U.S. production of uranium comes from open-pit mining, more than half of the identified resource is located at depths accessible only by underground mining. The long-term trend is expected to be towards underground mining at higher extraction costs. Another extraction process for underground mining is "in situ leaching," also at higher cost than open-pit mining.

The conversion process (Table IV-16, Step 3) takes the yellowcake and converts it to a volatile uranium hexafluoride. This results in chemical emissions and wastes, some of which are radiological in nature. Radiological sludge has to be held for reprocessing or burial. There are problems with heat dissipation, and water availability and contamination. There also is risk of accidents. All conversion in the U.S. occurs at sites in either Oklahoma or Illinois.

Gaseous diffusion enrichment (Table IV-16, Step 4) is accomplished by passing the volatile uranium hexafluoride compound through a process resulting in an enriched product. For this process air pollutants are associated with the emissions from coal fired electricity generation used for process power; especially particulates, NO_x and SO_2 . There are also air pollutants associated with the enrichment process itself. There are problems with heat dissipation, water availability, waste storage and disposal, radiological materials, and risk of accident. All enrichment in the U.S. is done by Department of Energy contractors in Tennessee, Kentucky, or Ohio.

Fuel fabrication (Table IV-16, Step 5) is accomplished by chemically converting the enriched uranium hexafluoride to a derivative and then mechanically processing it, including pellet and fuel element production. The fuel components are loaded into stainless steel tubes, fitted with end caps and welded. Air emissions result from the coal fired generation of process power and the fabrication process itself. There are problems with heat dissipation, disposal of radioactive waste, and risk of accident. Fuel

fabrication for the Trojan nuclear power plant, located just north of Portland, Oregon, is done in Connecticut. Fabrication for Supply System Plants 1 and 2 will probably be done in Washington.

There are two types of light water reactors, the boiling water reactor (Table IV-16, Step 6) and the pressurized-water reactor. The environmental effects of the two types of reactors are similar. There are airborne chemical effluents from the cooling towers and gaseous radioactive releases from the power facilities. There are liquid chemical effluents, some of which are radioactive. Considerable water is used. The spent fuel is presently stored at the reactor site. Provisions must be made for permanent spent fuel disposal, decontamination and decommissioning at the end of the 30 year expected life of the facility. There is also risk of accident.

5. Coal System

Table IV-17 contains information on the major pollutants associated with a 500 MW conventional coal boiler. This table presents information on environmental impacts on a system basis, tracing the process from mining of ore through the generation of electricity. The material is presented in separate steps because of the complexity of the information involved. The resources used, residuals and products are presented per trillion Btu's of energy produced. As was the case for nuclear systems, this allows cross comparisons between energy system tables.

The annual energy production of a representative 500 MW coal system is assumed to be 10.8 trillion Btu/year, given a 70 percent capacity factor and a 3.5 percent transmission loss factor. Therefore, the individual effects, such as air pollutants, can be multiplied by 10.8 to determine the cumulative impact of a 500 MW coal system. The following discussion summarizes by step the data presented in the table on the environmental impacts of coal energy systems from mining to electricity generation.

Following through the similar system analysis for coal fired generation, a typical area strip mine (Table IV-17, Step 1) for western coal (Wyoming and Montana) operates by segregating the topsoil for subsequent reclamation purposes and, after blasting, the overburden (averaging 70 feet) is removed in long parallel cuts. The newly exposed and blasted coal seam (averaging 25-30 feet) is removed. With the exception of the topsoil, overburden from each cut is placed over the previous cut. Coal is loaded into trucks for transportation to a coal cleaning area. Reclamation consists of grading the soil, replacing the topsoil and initiating revegetation. Aquifers in mined areas may be permanently disrupted. Mining could displace existing land uses such as agriculture and grazing, although similar use can be made of reclaimed areas, since mining companies are required to reclaim mined lands by approximating the original topography and planting suitable vegetation. Nevertheless, the lands are irretrievably altered and the reclamation may not fully restore the original productivity of the land. Opening new mines and expanding existing ones can result in significant influx of new population into remote areas and can have significant social and economic impact.

TABLE IV-17. STEP 1. **SURFACE COAL MINING — WESTERN**

REFERENCE ENERGY SYSTEM

The reference energy system consists of a surface mining operation in the Western United States. The mine is utilizing area strip mining techniques and configurations to remove coal from a 25- to 30-ft-thick seam, with a removal efficiency of 89% based on total coal in place. The coal is assumed to have 21.5% moisture, 34 to 35% volatile matter, 39.6% fixed carbon, 4.4% ash, and 0.4% sulfur by weight. Major equipment involved in the mining operation includes draglines, coal shovels, bulldozers, front-end loaders, scrapers, and trucks.

FACILITY OPERATING PARAMETERS

Size:	6×10^6 tons/yr
Annual Capacity Factor:	Not determined
Annual Energy Production:	110×10^{12} Btu (equivalent)
Efficiency:	89%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Feed Materials</u>				
Raw coal in place				Assumed to be 30-yr or more supply
<u>Energy</u>				
Fuel	880 × 10 ⁹ Btu	930 × 10 ¹² J	8 × 10 ⁹ Btu	
Electricity	12 × 10 ⁶ kWh	12 × 10 ⁶ kWh	0.11 × 10 ⁶ kWh	
<u>Water</u>				
Consumption	300 acre-ft	400 × 10 ⁶ l	3 acre-ft	
	Total Usage			
<u>Land</u>				
Fixed	40 acres	20 ha	0.4 acre	
Incremental	200 acres	80 ha	1.8 acres	
<u>Personnel</u>				
Construction	380 workers		3.5 workers	
Operation and maintenance	380 workers		3.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
		(1977 \$)	
Construction	$\$170 \times 10^6$ total	$\$1.55 \times 10^6$ total	
Operation and maintenance	$\$31 \times 10^6$ /yr	$\$0.28 \times 10^6$ /yr	
<u>Environmental Controls</u>			
	Not Determined		

TABLE IV-17.
STEP 1 cont.

SURFACE COAL MINING — WESTERN

ENVIRONMENTAL RESIDUALS				
	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	9 tons	8 tonnes	0.08 ton	75 μg/m ³ annual*
Sulfur dioxide	22 tons	20 tonnes	0.2 ton	80 μg/m ³ annual*
Oxides of nitrogen	220 tons	200 tonnes	2.0 tons	100 μg/m ³ annual*
Hydrocarbons	22 tons	20 tonnes	0.2 ton	
Carbon monoxide	130 tons	120 tonnes	1.2 tons	10 × 10 ³ μg/m ³ annual*
<u>Water Pollutants</u>				
Total dissolved solids	2.63 × 10 ³ tons	2.39 × 10 ³ tonnes	23.9 tons	250 mg/l*
• Iron	0.6 ton	0.5 tonne	0.005 ton	0.3 mg/l*
• Manganese	2.2 tons	2.0 tonnes	0.02 ton	0.050 mg/l*
• Aluminum	0.7 ton	0.6 tonne	0.006 ton	
• Zinc	0.6 ton	0.5 tonne	0.005 ton	5 mg/l*
• Nickel	0.11 ton	0.10 tonne	0.001 ton	0.046 mg/l*
Total suspended solids	250 tons	230 tonnes	2.3 tons	
• Iron	2.2 tons	2.0 tonnes	0.02 ton	
Ammonia	22 tons	20 tonnes	0.2 ton	0.02 mg/l*
Sulfate	3.60 × 10 ³ tons	3.27 × 10 ³ tonnes	32.7 tons	250 mg/l*
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		
*Regulatory compliance level.				

PRODUCTS				
	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
	<u>Primary</u>			
Run-of-mine coal	6.00 × 10 ⁶ tons	5.45 × 10 ⁶ tonnes	54.5 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH				
Not Determined				

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-17. STEP 2.

COAL BENEFICIATION

REFERENCE ENERGY SYSTEM

The system is comprised of a number of wet circuit coal beneficiation devices including crushers, scalping screens, rotary breaker, vibrating screens, jigs, thickeners, concentrating tables, flotation circuits, and thermal drying. These devices are designed to remove unwanted components from the raw coal, such as ash to improve the energy content or sulfur to reduce the sulfur oxide emissions. The resultant cleaned coal can then be utilized in a manner essentially identical to other unprocessed coal that has not undergone this degree of beneficiation.

FACILITY OPERATING PARAMETERS

Size:	2.857×10^6 tons/yr
Annual Capacity Factor:	83% (based on 230 days/yr of operation)
Annual Energy Production:	55.0×10^{12} Btu
Efficiency:	87.5%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (run-of-mine)	2.86 × 10 ⁶ tons	2.59 × 10 ⁶ tonnes	51.945 × 10 ³ tons	
<u>Energy</u>				
Electricity	11 × 10 ⁶ kWh	11 × 10 ⁶ kWh	0.20 × 10 ⁶ kWh	
Oil	32 × 10 ⁹ Btu	34 × 10 ¹² J	0.59 × 10 ⁹ Btu	
<u>Processing Materials</u>				
		Not Determined		
<u>Water</u>				
Consumptive uses	200 acre-ft	250 × 10 ⁶ l	3.7 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>				
	240 acres	96 ha	4.3 acres	
<u>Personnel</u>				
Construction (1 yr)	440 workers		8.1 workers	
Operation and maintenance	82 workers		1.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
		(1976 \$)	
Construction (1 yr)	$\$24 \times 10^6$ total	$\$0.43 \times 10^6$ total	
Operation and maintenance	$\$18 \times 10^6$ /yr	$\$0.32 \times 10^6$ /yr	
<u>Environmental Controls</u>			
		Not Determined	

TABLE IV-17. STEP 2 cont.

COAL BENEFICIATION

ENVIRONMENTAL RESIDUALS				
	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	50 tons	40 tonnes	0.9 ton	
Sulfur dioxide	0.3 ton	0.2 tonne	0.005 ton	
Oxides of nitrogen	33 tons	30 tonnes	0.6 ton	
Hydrocarbons	11 tons	10 tonnes	0.2 ton	
Carbon monoxide	11 tons	10 tonnes	0.2 ton	
<u>Water Pollutants</u>				
Total dissolved solids	1.82 × 10 ³ tons	1.65 × 10 ³ tonnes	33 tons	
• Iron	0.4 ton	0.3 tonne	0.007 ton	
• Manganese	1.6 tons	1.5 tonnes	0.03 ton	
• Aluminum	2.2 tons	2.0 tonnes	0.4 ton	
• Zinc	0.3 ton	0.2 tonne	0.005 ton	
• Nickel	0.16 ton	0.15 tonne	0.003 ton	
Total suspended solids	33 tons	30 tonnes	0.6 ton	
• Iron	3.3 tons	3.0 tonnes	0.06 ton	
Ammonia	3.0 tons	2.0 tonnes	0.05 ton	
Sulfates	990 tons	900 tonnes	18.0 tons	
<u>Solid Wastes</u>				
Course cleaning	0.11 × 10 ³ tons	0.1 × 10 ³ tonnes	0.002 × 10 ³ tons	
Primary cleaning	559 × 10 ³ tons	508 × 10 ³ tonnes	10.16 × 10 ³ tons	
Froth flotation	290 × 10 ³ tons	260 × 10 ³ tonnes	5.3 × 10 ³ tons	
Breaking and sizing	0.11 × 10 ³ tons	0.1 × 10 ³ tonnes	0.002 × 10 ³ tons	
Total	849 × 10 ³ tons	768 × 10 ³ tonnes	15.5 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
May affect workers but not nearby receptors				

PRODUCTS				
	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
	<u>Primary</u>			
Coal (cleaned)	2.00 × 10 ⁶ tons	1.82 × 10 ⁶ tonnes	36.4 × 10 ³ tons	
<u>Recoverables/Recyclables</u>				
	Not Determined			

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-17. STEP 3.

WESTERN COAL UNIT TRAIN

REFERENCE ENERGY SYSTEM

Typical western unit train systems are comprised of 100 cars each holding 100 tons and four diesel locomotives of 3000 hp each. The train operates between two fixed locations on a dedicated basis. This example assumes a train traveling 700 mi one way and making 90 trips per year. Ten spare cars are reserved for each train system.

FACILITY OPERATING PARAMETERS

Size:	100 cars, 100 tons per car, 10×10^3 tons per train
Annual Capacity Factor:	Not determined
Annual Energy Production:	17.01×10^{12} Btu (coal transported)
Efficiency:	99.69% based on $\frac{\text{energy delivered}}{\text{energy loaded} + \text{energy expended}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	900 × 10 ³ tons	817 × 10 ³ tonnes	52.9 × 10 ³ tons	
<u>Energy</u>				
Diesel	221 × 10 ⁹ Btu	233 × 10 ¹² J	13.0 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Aluminum	43.2 tons	39.2 tonnes	2.54 tons	
Brass and bronze casting	17.4 tons	15.8 tonnes	1.02 tons	
Chromium	2.2 tons	2.0 tonnes	0.13 ton	
Copper	59.7 tons	54.2 tonnes	3.51 tons	
Iron		Not Determined		
Manganese	30.6 tons	27.8 tonnes	1.80 tons	
Nickel	0.51 ton	0.46 tonne	0.03 ton	
Steel	4.27 × 10 ³ tons	3.88 × 10 ³ tonnes	251 tons	
<u>Land</u>				
Land value has been excluded as it cannot be exclusively associated with coal transportation				
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	120 workers		7.02 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
	(1978 \$)		
Construction	$\$7.70 \times 10^6$ total	$\$0.454 \times 10^6$ total	
Operation and maintenance	$\$6.87 \times 10^6/\text{yr}$	$\$0.403 \times 10^6/\text{yr}$	

TABLE IV-17, STEP 3 cont. **WESTERN COAL UNIT TRAIN**

ENVIRONMENTAL RESIDUALS				
	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	2.38 × 10 ³ tons	2.16 × 10 ³ tonnes	140 tons	
Sulfur dioxide	90 tons	80 tonnes	5.0 tons	
Oxides of nitrogen	75 tons	68 tonnes	4.4 tons	
Hydrocarbons	61 tons	56 tonnes	3.6 tons	
Carbon monoxide	78 tons	71 tonnes	4.6 tons	
Aldehydes	14 tons	12 tonnes	0.8 ton	
<u>Noise Pollution*</u>				
In-cab noise level		≥ 112 dBA		Federal design levels:
100 ft from moving train		~ 95 dBA		55 dBA – residence
1000 ft from moving train		~ 75 dBA		75 dBA – open land
Whistle noise at 1000 ft		≤ 85 dBA		
*Noise cannot be expressed in terms of energy produced.				

PRODUCTS				
	<u>Quantities Produced</u>			<u>Remarks</u>
	Reference Energy System		<u>Per 10¹² Btu Energy Produced</u>	
	<u>Annual Production</u>			
	<u>English Units</u>	<u>Metric Units</u>		
	<u>Primary</u>			
Coal transported	900 × 10 ³ tons	817 × 10 ³ tonnes	52.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH				
Not Determined				

SOURCE: Technology Characterizations Environmental Information Handbook, U.S. Department of Energy, June 1981c.

TABLE IV-17.
STEP 4.

COAL-FIRED POWER PLANT — WESTERN COAL

REFERENCE ENERGY SYSTEM

The system is composed of a conventional steam electric power plant using typical western low-sulfur subbituminous coal supplied by a unit train operation. No cogeneration is included. Environmental control systems include electrostatic precipitators for particulate control, wet lime/limestone scrubbers for sulfur dioxide control, onsite solid waste disposal, and onsite water treatment for water recirculation to eliminate liquid discharges. The plant is assumed to be subject to current regulations.

FACILITY OPERATING PARAMETERS

Size: 500 MWe
Annual Capacity Factor: 80%
Annual Energy Production: 12×10^{12} Btu
Efficiency: 35%
Lifetime: 30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Run-of-mine subbituminous coal	2.11 × 10 ⁶ tons	1.92 × 10 ⁶ tonnes	0.18 × 10 ⁶ tons	Low-sulfur coal (0.63% sulfur)
<u>Processing Materials</u>				
Limestone to sulfur dioxide scrubber	32 × 10 ³ tons	29 × 10 ³ tonnes	2.7 × 10 ³ tons	
Fly ash (sludge fixing)	100 × 10 ³ tons	92 × 10 ³ tonnes	8.4 × 10 ³ tons	
<u>Water</u>				
Water consumed (generating plant)	4.9 × 10 ³ acre-ft	6.1 × 10 ⁹ l	0.41 × 10 ³ acre-ft	
	Total Usage			
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>				
Plant and solid waste disposal (ash and scrubber sludge)	156 acres	63.1 ha	12.9 acres	Additional land required for water and coal storage and buffer zone
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	155 workers		13.0 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
Construction		Not Determined	
Operation and maintenance		↓	
<u>Environmental Controls</u>			
		Not Determined	

Air residuals originate from the diesel powered equipment used to dig and haul coal and overburden, and from dust due to wind erosion and vehicular operation. Reclamation and revegetation of mined areas and dust suppression practices can reduce the particulates generated by wind erosion. Water pollution occurs from suspended solids produced by runoff from piles of overburden, but under controlled conditions coal pile drainage and runoff are collected and treated prior to discharge to reduce suspended solids to a concentration of 30 parts per million (ppm) and obtain a zero acid content. There are accident risks associated with surface mining, although the risk is not as severe as that associated with underground mining.

Coal beneficiation (Table IV-17, Step 2) is a nine step process for upgrading coal prior to its use for utility purposes. The purpose of beneficiation is to remove impurities, such as ash or sulfur, from the raw coal. The degree and type of beneficiation depends on the type of coal. Coal from the Western States is relatively clean. The breaking and sizing processes result in noise and require small amounts of water for dust control. In addition, land is required for both breaking and sizing as well as for loading and storage facilities.

Coal can be transported (Table IV-17, Step 3) from the mine to the generating plant by train, truck, or coal slurry pipeline. A 500 MW plant would require on the average over 3,000 tons of coal per day. With new unit train cars carrying 100 tons per car, 30 cars would be used for one day's generation of electricity. Train hauling results in noise, emissions from diesel fuel combustion and wind borne particulates. These particulate emissions during transportation have been estimated to be less than 1 percent of tonnage carried by unit trains. Coal slurry pipelines require large amounts of water. For example, Peabody Coal's Black Mesa slurry pipeline requires about 11 million gallons of water per trillion Btu's of coal carried (3,200 acre-feet per year). It also requires a 62.5 foot right-of-way along its length (7.58 acres per mile) and 50 acres for each of four pumping stations.

The environmental concerns associated with the generation of electricity from a conventional boiler (Table IV-17, Step 4) consist of SO₂, CO and NO_x emissions, leachate of trace elements from ash/sludge and water use. There is potential for accidents.

The chemical air emissions of coal fired plants are of special concern. Emissions from coal plants to the atmosphere (SO₂ and NO_x) can result in acid precipitation which may have corrosive effects on a variety of materials as well as potential detrimental effects on aquatic and terrestrial life. Currently, intensive research is being conducted on acid precipitation (refer to III.B.1.g.).

The second emission of major concern from the combustion of coal is carbon monoxide. This emission contributes to the problem of carbon dioxide (CO₂) in the atmosphere which is becoming a worldwide problem. The combustion of all forms of fossil fuels, not just coal, is the major source of CO₂. Concentration of CO₂ in the earth's atmosphere is known to have increased about 7 percent since 1958 and could reach levels of 30-50 percent above the 1958 level by the middle of the twenty-first century (Council on Environmental Quality, 1980b, p. 265).

Atmospheric CO² has "greenhouse" effects by trapping heat, causing the average temperatures of the earth's surface to rise. It is estimated that a doubling of the atmospheric CO² concentration could raise average global surface temperatures about 3 degrees centigrade (5.4 degrees fahrenheit) and increase the winter average in the north polar region as much as 7 to 10 degrees centigrade (Council on Environmental Quality, 1980b, p. 265).

Using Tables IV-16 and IV-17, it is possible to summarize the major impacts of a coal and a nuclear generating system (mining through generation). The impacts associated with a 1000 MW nuclear generating facility and a 500 MW coal facility are summarized in Table IV-18.

6. Combustion Turbines

Combustion turbines are rotary engines similar in design and operation to a jet aircraft engine. Rather than providing thrust as does an aircraft engine, however, the hot combustion gases from a stationary gas turbine drive a power output shaft. The gasses are then exhausted to the atmosphere through a muffling sytem. This process is called simple cycle. In a combined cycle operation, additional turbines are powered by steam produced from turbine waste heat. Combustion turbines generally are powered by fossil fuels; either natural gas or various types of distillate fuels.

Combustion turbines in the Pacific Northwest are used to supplement baseload generation plants. Hydro and thermal baseload plants may be insufficient to meet firm loads during unusual conditions or emergencies. Portland General Electric's Beaver Combustion Turbine Plant, for example, essentially operated at full capacity in 1979 when the Trojan Nuclear plant was inoperative. An additional potential benefit of combustion turbines is that they provide backup for increased overdrafting capability from hydro plants, thus providing more system flexibility. Typically, most plants operate for short periods, and operate at well below 20 percent plant factor (a concept similar to plant capacity utilization) for the year. The limited operation of plants results in part from the plants' intended function as peaking units, relatively expensive fuel and operating costs, and State and Federal environmental regulations.

The number of combustion turbines in the U.S. has increased considerably since the mid-1960's. In the Pacific Northwest, there are 13 operational simple cycle generating units and one combined cycle unit is scheduled for completion during Fall 1983.

Some of the characteristics of combustion turbines that account for their recent popularity are (1) they can be built quickly and at relatively low cost; (2) short start-up time to meet emergency loads; (3) good reliability; and (4) ability to operate with a variety of fuels in most environments.

Unavoidable adverse impacts of combustion turbines are 1) fossil fuels are consumed, and 2) pollutants are discharged.

TABLE IV-18
MAJOR ENVIRONMENTAL IMPACTS OF REPRESENTATIVE
COAL AND NUCLEAR GENERATING SYSTEMS,
FROM MINING THROUGH GENERATION

Line No.	Type of Impact	A 1,000 MW Nuclear Plant a/	B 500 MW Coal Plant b/
1.	Total Land Use (acres)	308.0	180.1
2.	Land Disturbed-Mining (tons of overburden) c/	3,038,000.0	8,046.0
3.	Air Pollution:		
4.	Particulates	1,247.1 d/	6,598.8
5.	SO ₂	4,356.9	6,537.4
6.	NO _x	1,225.3	9,255.6
7.	Hydrocarbons	12.1	367.2
8.	CO	130.6	1,036.8
9.	Other	7.6 d/	3,348,004.3 e/
10.	Solid Waste (tons)	195,383.8 d/	589,680.0
11.	Water Pollutants (tons)	4,420.9 d/	12,211.8

a/ Annual energy production of 21.7 trillion Btu/year (Conversion factor: 1 kilowatthour = 3,412 Btu's).

b/ Assumes plant operates under revised Federal standards which impose environmental controls. Annual energy production of 10.8 trillion Btu/year.

c/ Assumes 100 percent land reclamation leaving no waste.

d/ Includes radioactive pollutants.

e/ Includes 3,348,000 tons of CO₂.

Source: BPA

The major pollutants of combustion turbines are suspended particulates, and nitrogen and sulfur oxides. The extent and impact of these pollutants are dependent on site characteristics, turbine characteristics, and the type and quality of fuel used.

Many site specific environmental impacts may be mitigated or avoided. Dispersal of pollution is influenced by local weather conditions, or terrain such as bluffs or hills that may act as a barrier to dispersal of pollutants from the plant. Access to fuel sources is an important consideration. Distillate fuels that must be received by truck may noticeably increase traffic in the vicinity of the plant. Noise impacts may be controlled through sound deadening devices and open space buffering. A combined cycle plant of 300 MW may require a 400-acre parcel for an adequate buffer.

Emissions of nitrogen oxides may be relatively cheaply and effectively reduced through a method of water or steam injection into the gas turbine combustors. The water and solid waste pollution from this process is minimal because the wastewater may be sewerred directly.

The most cost effective method of reducing emission of sulfur oxides is to minimize the use of high sulfur fuel oils.

7. Generation Assumptions

The environmental data for the coal fired generation facility is based on an 80 percent plant factor (or capacity factor). For the comparative environmental analysis, the operational impact data for the coal facility were computed at a 70 percent plant factor to correspond with the 70 percent plant factor applied to operational impacts of nuclear facilities (see Table IV-16, Step 6). Certain impacts, such as land required for the plant site and a portion of land impacts at mine sites, are fixed amounts which do not vary with plant factor levels. Therefore, a portion of the impacts was reflected as fixed amounts based on information from Tables IV-16 and IV-17.

Plant factor is an estimate of the average percent of nameplate capacity at which a resource is operated over the course of a year. A 1000 MW nameplate plant, for example, could be expected to produce an average useable capacity of 700 MW, assuming a 70 percent plant factor. While actual plant factors vary according to plant type (nuclear versus coal, for example), vintage, and specific operating and maintenance characteristics, staff chose 70 percent because it is a reasonable capacity factor that can be assumed for either a coal or nuclear plant. The resulting estimated coal plant impacts are somewhat higher on a per kilowatthour basis than if staff had used the 75 percent capacity factor assumed for coal plants in BPA's latest TDLRIC Analysis (BPA, 1983f), since the fixed impacts are spread over fewer kilowatthours of produced energy.

Since coal and nuclear facilities would serve as baseload plants in BPA's generation system, these plants would be assumed to operate at their full capacity whenever they were in operation. A loss factor of 3.5 percent was used to estimate the power lost during transmission from point of power production to point of power consumption.

I. Study of Alternative Rates

The purpose of this section is to discuss the various stages of rate development and analyze the implications of decisions at each stage. First, the process is described in general terms. Later sections analyze each step in the development process.

General Process: The proposed revenue requirement (see also Section II. B.) specifies the total costs which have to be recovered from BPA's customers. The rates to recover this revenue requirement are discussed in a two steps. The cost allocation steps begin by identifying the costs as occurring because of the utility system's function of transmitting or generating power. The generation costs are then split between those incurred to provide capacity and those incurred to provide

energy. Finally, costs are allocated to customer classes according to the amount and quality of power purchased to serve each class. The rate design step begins by discussing the adjustments made to allocated costs based on policy or legal considerations. Various rate design changes are then made and, finally, rates are developed to recover the adjusted costs from each customer class.

To cover the cost of supplying power to utilities for resale to consumers and to the DSI's for direct consumption; BPA develops charges for transmission, capacity, and energy. Transmission charges cover the cost of bringing power from the generation facilities to the distribution systems of the retail utilities. Costs of the transmission system are allocated between Federal and non-Federal power utilizing the system. The Federal part of the cost is recovered by wholesale power rates. The non-Federal part is recovered by transmission rates. Capacity charges, also called demand charges, cover the costs BPA incurs in being ready to meet the load placed on the Federal system at any given instant. It is a charge per kilowatt to cover the costs of the development of the system of generating facilities to meet the largest or peak anticipated customer load. Energy charges per kilowatthour cover the costs of running the system of generating facilities. Energy costs are determined according to the amount of actual usage.

The total revenue to be recovered from wholesale power rates is developed in the Revenue Requirement Study. The total revenue requirement is made up of costs which include capital and annual costs of generation, transmission and other costs of the FCRPS and other obligations for which BPA has incurred costs, or expects to incur costs, in order to serve customer loads. Decisions which change costs at this level, change the revenue required from rates.

The following sections discuss two conceptual stages of rate development: (1) allocating the costs, and (2) designing the rates. Major issues or alternatives relative to this rate period are identified and analyzed. The implication of decisions during each of the stages is discussed.

1. Cost Allocation

After establishing the amount of revenue needed to be recovered from the rate pools, the process of cost allocation follows several steps: functionalization, classification, time differentiation, and allocation to classes of service. These different steps can be considered increasingly specific ways of allocating costs. The first step is a broad split of costs. The final steps are assignment of specific costs to specific customer classes. Each step is described, issues and alternatives are discussed and implications are analyzed.

a. Functionalization

Functionalization is the initial step taken to identify costs as they relate to functions performed by the utility system. These functions are defined as generation and transmission. Costs incurred for another function of the utility system, related to metering and billing

activities, are considered to be subfunctions of generation and transmission services provided by the system. All costs are assigned to one or more of these functions.

Issues: Issues over functionalizing costs occur regarding costs which are not clearly distinguishable as belonging to either generation or transmission. These include the deferral, conservation program costs, fish and wildlife program costs, exchange costs, and operation and maintenance.

BPA functionalizes the deferral to both generation and transmission in the same proportion as all other revenue requirements in the COSA because accurate identification cannot be made of the cause of the deferral. Conservation program costs are functionalized entirely to generation because such funding is specifically to reduce the need for constructing new generation resources. Exchange costs are functionalized to both generation and transmission based on each exchanging utility's average system cost calculation. Operation and maintenance are functionalized to generation, transmission, or the subfunction of metering and billing based on the Direction of Effort Study. This study is an analysis of BPA's staff and use of facilities to identify the proportion of time and effort devoted to each system function.

Alternatives: Alternatives to BPA's approach to functionalization pertain to a different split of costs between system functions. For example, one alternative is to functionalize conservation costs to transmission in addition to generation. However, the region is constrained by the availability of generation resources and conservation funding is undertaken specifically to reduce the need for constructing new generation resources. While conservation also reduces the need for transmission facilities, based on the cost causation principles of the COSA, conservation costs are functionalized to only generation.

b. Classification

Classification is the process of dividing the functionalized generation costs between those incurred to provide capacity (demand) and those incurred to provide energy. A utility must provide enough generating capacity to meet system peaks, and must provide energy over time. In the past, the Federal hydro system was sufficient to meet both capacity and energy loads. However, regional growth has promoted almost the full development of cost-effective hydro sites for energy production. Additional capacity (peaking) requirements have been met primarily through the construction of additional units at existing hydro projects. The region has now turned to thermal facilities to meet growth in the demand for energy. Thermal plants are not easily fired up and shut down quickly and are therefore less suited to responding to capacity requirements. Thermal plants, however, can operate on a sustained schedule and have a large output which is suitable to meet the region's base energy load. As new thermal energy generation is expensive to build and operate, there has been a shift in the relationship of energy and capacity costs. The incremental cost of energy (the cost of adding new thermal energy

resources) is now increasing faster than the incremental cost of capacity. Furthermore, in the long term, the region is forecast to need new energy resources before it will need new capacity resources.

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

BPA incurs generation costs for different types of resources and programs. BPA's generating facilities consist of a mix of hydro and thermal resources. BPA also acquires exchange generating resources, and funds conservation programs that reduce the need to build and operate additional generating facilities. Since these major types of generation costs are incurred for different reasons, separate classification approaches are used.

In the classification of the costs of the Federal hydro system, all hydro units installed solely to provide peaking capacity are identified. Hydro units which provide no incremental energy are considered to be peaking units. Costs of these units are classified entirely to capacity. All other units in the Federal hydro system are considered to be base hydro units and provide energy as well as capacity. The costs of the base hydro system have therefore been apportioned between energy and capacity on the basis of the operational characteristics of the Federal hydro system.

Baseload thermal plant costs are classified on the basis of the results of the TDLRIC Analysis. The primary reason for the construction of large baseload thermal plants is to produce energy. For efficient operation, baseload thermal plants are generally operated at the highest possible plant factor to minimize the cost of energy production. Baseload plants also provide capacity; however, such capacity could be provided by the most economical alternative to a base load thermal plant, which, in the long run, is considered to be a single cycle combustion turbine. Therefore, the cost of purchasing baseload thermal plant capability is classified by crediting total thermal plant costs with an amount equal to the cost of the alternative combustion turbine. The amount credited is the capacity component of the thermal plant costs. The alternative peaking costs for the combustion turbine are developed in the TDLRIC Analysis. The costs remaining after application of the capacity credit are classified to energy. TDLRIC classification percentages are applied to New Resources costs as well as to thermal plant costs.

Conservation is assumed to be a reduction in loads. Conservation costs are classified on the basis of the amount of energy and capacity savings projected, as well as the relative long run incremental costs that would be incurred had resources been required to provide the power which is conserved.

IOU Exchange Costs are classified on the basis of classifications of cost allowed by regulatory bodies within the region; either on the basis of inter-jurisdictional classifications of cost, or on classifications used in the design of rates by exchanging utilities. Public Agency exchange costs are classified on the basis of the overall classification of Federal resources used to serve such loads.

Costs not specifically related to resources, such as BPA administrative costs, the deferral, and cash lag adjustment are classified on the basis of the overall classification of all of BPA's other revenue requirements. Fish and Wildlife Program costs are assumed to be costs related to the operation of the Federal hydro system, and are classified on the basis of the classification of all other Federal hydro costs (both peak and base). All transmission costs allocated to Federal power are classified to capacity. (For further information see BPA, 1983a).

Issues: As with functionalization, issues occur over classifying costs which are not clearly distinguishable as belonging to either capacity or energy. One such issue is the use of the combustion turbine as the most economical capacity alternative to a base load thermal plant. Other issues occur over the basis of classifying costs. For example, costs could be classified based on actual resource use rather than on the reason a resource was originally constructed or acquired. The importance of these issues is in relation to their impact on the overall pricing classification of energy and capacity.

Alternatives: There are a number of alternative methods for classifying energy and capacity costs: all or most costs could be classified to capacity; all or most to energy; all costs could be classified according to the results of the TDLRIC Analysis; a fixed/variable method could be used. Each of these alternatives is discussed. A table summarizing all of the classification methods is in the last part of the section.

How capacity versus energy costs are classified has important implications for different customers. Recovery of all or most energy and capacity costs through a capacity (demand) charge would provide a utility customer with a strong incentive to take power at a uniform rate, minimizing peak demand relative to average demand. An example of such a customer would be a utility with a high proportion of industrial customers with relatively high around-the-clock consumption throughout the year. This customer would have a high annual load factor or a high ratio of average demand to peak demand. The high capacity charge would offer little or no incentive to the customer to constrain their energy requirements, which have a high incremental cost.

Conversely, recovery of all or most costs through an energy charge would provide an incentive to a utility customer to conserve energy. This would benefit a customer with a low annual load factor or a low average demand related to peak demand. An example of such a customer would be a utility with a high proportion of residential consumers. The high energy charge would offer little incentive to constrain peak demand.

Also, encouragement of low annual load factor could lead to under-utilization of the power system since the system would be "overbuilt" in order to meet peak demand and not fully used in off-peak time.

An important consideration in the classification of capacity and energy costs is BPA's revenue sufficiency and stability. Capacity costs are recovered by a charge per kilowatt; energy costs by a charge per kilowatthour, based on actual consumption. A large portion of BPA's total annual costs are fixed obligations over which BPA has little discretion. A high energy relative to capacity charge signals the proper incremental cost relationship between these two products. It has been alleged that the greater the amount of BPA's total annual costs that are designated to be recovered from energy charges, which are subject to changes in consumption, the greater the potential for revenue difficulties. However, there is no clear empirical evidence supporting the claim that energy revenues are less stable than capacity revenues. Furthermore, the most relevant measure of revenue stability is the deviation of actual revenues from actual costs. Many factors may contribute to this problem such as general economic conditions and weather. To mitigate some of the potential for excess fluctuation of revenue, BPA can use rate design techniques which will be discussed in a latter section.

As a third alternative, all capacity and energy costs could be classified according to the classification percentages developed in the TDLRIC Analysis. Currently, BPA uses the TDLRIC Analysis to classify only thermal resources. Hydro resources are classified according to cost-causation. This alternative would provide the consumer with a price signal which would reflect the relative cost to society of additional kilowatts and kilowatthours, but the level of the charges would be constrained to preclude recovery of revenue in excess of BPA's revenue requirement. This would result in capacity and energy rates which would recover the revenue requirement in proportion to the incremental cost of each power component.

Use of the TDLRIC Analysis to classify costs would result in a change in relative costs, but would not reflect the differences in operating characteristics between thermal and hydro resources. For efficient operation, baseload thermal resources must be operated at high plant factors while hydro resources do not have this constraint. The TDLRIC-based charges for energy would be high, and those for capacity low, relative to the energy and capacity charges based on BPA's current classification methodology. Thus, this alternative, while correctly signaling relative incremental costs, would not encourage a consumption pattern conducive to the efficient operation of existing resources.

A fourth alternative is the classification of IOU Exchange costs using classification percentages from the TDLRIC Analysis, while classifying all other costs in a manner consistent with BPA's Initial Proposal. This alternative would more closely reflect BPA's incremental costs of capacity and energy than BPA's initial proposal which classified exchange costs based on information supplied by the exchanging utilities. However, application of TDLRIC classification percentages to exchange resources would not reflect BPA's cost causation for acquiring these

resources. The costs associated with exchange resources represent costs incurred by the exchanging utilities for resources in a mix which is similar to BPA's mix of hydro and thermal resources.

The final alternative classification system is a fixed/variable approach. This alternative assigns all fixed generation costs to capacity and all variable generation costs to energy. In the short run, all costs which do not vary with output are fixed costs. Therefore, this classification scheme would result in the majority of both hydro and thermal plant costs being assigned to capacity. However, such a weighting of capacity charges does not reflect the capacity and energy relationship developed during the planning of the Federal system. Furthermore, it would send inappropriate price signals concerning the relative incremental costs of capacity and energy because the region is building expensive thermal plants to produce energy, not capacity.

Table IV-19 summarizes BPA's classification methodology and each of the alternatives discussed. The table also has a generalized capacity and energy resource summary. If it is known that the overall capacity charge will increase relative to the energy charge, or vice versa, this table can be used to evaluate other alternatives.

BPA analyzed the effects of three classification alternatives on allocated costs to its various customer classes. Capacity costs, energy costs, and total costs under each alternative were compared to allocated costs in the initial proposal.

The three alternatives which were analyzed included Fixed/Variable classification, LRIC classification of exchange costs, and LRIC classification of all costs. Under the Fixed/Variable Alternative, 90 percent of all generation costs were classified to capacity, with the remaining 10 percent classified to energy, based on the assumption that 90 percent of BPA's generation cost are fixed costs. The LRIC classification of exchange costs alternative assumed that, in addition to thermal power costs, exchange costs and classified using TDLRIC percentages. Classification of all other resources was kept consistent with BPA's initial proposal. The final alternative, LRIC of all costs, applied TDLRIC classification percentages to all generation costs. For all three alternatives, 100 percent of transmission costs were classified to capacity consistent with the initial proposal. Time constraints precluded BPA from accounting for expected changes in capacity and energy loads in response to changes in the relative costs of energy and capacity under alternative classification assumptions. BPA used the load estimates which were developed for the initial proposal for all three classification alternatives. In reality, elasticity responses to changes in price for energy and capacity would likely occur in varying degrees among BPA's customer classes, resulting in changes in both size and proportion of demand and energy loads among classes. This would influence, to some degree, the amounts of energy and capacity costs ultimately assigned to each customer class. However, BPA's analysis of alternatives did provide a basis for evaluating the direction and relative magnitude of changes in allocated costs among customer groups that would result from various changes in BPA's classification methodology.

TABLE IV-19
COMPARISON OF CLASSIFICATION ALTERNATIVES

<u>Resource Summary</u>	<u>Capacity</u>	<u>Energy</u>
definition	Cost of peak system	Cost of running system
measurement	kilowatts	kilowatthours
base system	hydro supplied	thermal supplied
resource cost	low	high
operating cost (fuel)	low (hydro); high (C. T.) <u>1/</u>	low
incremental cost	low	high
long-run availability	sufficient	deficient
<u>BPA Proposed Classification</u>		
Energy costs slightly higher than capacity costs. (53% energy, 47% capacity) <u>2/</u>	Reflects relative low incremental cost of capacity for thermal resources without overlooking the causes underlying development of the hydro system.	Reflects relative high incremental cost of energy; some incentive to conserve while still encouraging efficient resource operation.
<u>Alternatives</u>		
1. High Capacity Charge, Low-Energy Charge	Incentive to reduce peak which might result in underutilization of hydro peaking capability; favors high annual load factor customers.	Less incentive to conserve energy; may require construction and operation of new thermal resources while resulting in underutilization of hydro peaking capability.
2. High Energy Charge, Low-Capacity Charge	Less incentive to reduce peak; may require new units to be added to existing sites (hydro in near term, combustion turbines in long term).	Incentive to conserve; lessens efficient operation of existing energy resources; favors low annual load factor customers
3. TDLRIC (83% energy 17% capacity)	Reflects low incremental cost of capacity; could minimize costs incurred to meet load growth.	Reflects high incremental cost of energy; incentive to conserve; lessens efficient operation of existing energy resources.

TABLE IV-19, Cont.

<u>Alternative</u>	<u>Capacity</u>	<u>Energy</u>
4. Fixed/Variable	All fixed costs; results in high relative capacity charge (see Alternative 1).	All variable costs; results in low relative energy charge. (see Alternative 1).

1/ Combustion turbines are long-term peaking alternative.

2/ Percentages represent total costs recovered through rates.

c. Time Differentiation

Time-differentiated pricing is based on the concept of cost causation. The goal of time-differentiated pricing is to develop correspondence between power rates and variations between time periods in the cost of power production. The time periods to which rate differentials can apply include seasons of the year and periods of the day. (BPA has seasonally differentiated costs in the COSA process and diurnally differentiated costs in the rate design process.) Time differentiation of rates has the goal of sending proper price signals about the cost of power production. These signals have the effect of reducing peak demand and increasing load during off-peak hours. Time differentiation is recognized as a successful mechanism for accomplishing both of these effects (see Section IV.I.1.c.). BPA's system has a daily peak (7 a.m. to 10 p.m.) and a seasonal (winter) peak.

Seasonal rate differentiation is based on the cost of operation of BPA's generating resources which consist of a large number of plants, many of which are also operated for other purposes (flood control, navigation, irrigation, recreation). Seasonal operations consist of preparing an annual plan of operations prior to the start of a year, and implementing the plan on a week-to-week basis. Decisions are made at the seasonal operations level regarding the amounts of firm energy and capacity which the generating system can produce under adverse conditions; operation of major reservoirs on a month-to-month and week-to-week basis; availability of energy for service to nonfirm loads; and other adjustments to loads and resources for periods exceeding a few days.

The seasonal differentiation of energy rates is based on BPA's need to generate power from water stored in reservoirs. In general, cost to provide energy from FBS resources is the same for each hour of the year, except for the costs associated with the storage of water to meet the winter peak season energy requirements. Relatively small amounts of water from storage are used from April through August in contrast to the large amounts used from September through March. Therefore, the costs incurred for hydro storage facilities are allocated to the winter season and recovered through winter period energy charges.

The seasonal differentiation of capacity rates is based on an analysis of those periods for which there is the greatest probability of the capacity of the system being exceeded. Those months designated as having

a relatively high risk of load loss due to capacity being exceeded are assigned a proportionately higher rate than those months designated as low risk. In the past, the months December through May have been defined as the peak period, primarily because of the increased electricity consumption for lighting and heating during the winter period.

Differentiation by periods of the day (diurnal) is based on the cost of meeting the daily electric power demand for which BPA is the responsible generation scheduling and dispatching utility. Daily demand is a function of many things, including weather, time of day, day of week and season of the year.

In the Pacific Northwest, residential peak loads coincide with overall utility peaks. Space heating is the most significant component of both the diurnal and seasonal residential peak. Peak use of lighting, appliances and water heaters coincides with peak heating use. If the growth of peak load demand is slowed, the need for future expensive capacity additions can be reduced, thereby minimizing the cost of electricity. There could also be less negative environmental impacts associated with the construction and operation of additional peaking facilities.

Theoretically, by using a pricing differential, some of the load could be shifted from peak to off-peak use. A shift to off-peak could occur if a daytime load is shifted to the night (diurnal), or if a winter load is shifted to the summer (seasonal). Such shifts could mean an alteration of operating schedules and might be appropriate for some industrial and agricultural activities. A permanent shift of peak to off-peak use would produce an increase in BPA's annual load factor. In the short run, greater utilization of existing plants would allow costs to be spread over a larger volume of sales, resulting in lower costs per kilowatthour. In the long run, the higher annual BPA load factor would permit increasing use of baseload generation which could save fuel relative to the fuel requirements associated with operating thermal peaking units.

In theory, another use of time-differentiated rates is to help offset a decline in annual system load factor. Such a decline might occur if a low load factor sector, such as the residential sector, is expected to have an increasing share of regional electric use, relative to a high load factor sector (energy-intensive industry). The gradual increase of the price differential between peak and off-peak could counterbalance the effects of the changes in composition of regional loads (BPA, 1979b, p. VI-24).

To the extent that time-differentiated rates smooth BPA's load, river flow will be less variable. A reduction in river fluctuation would be generally beneficial to aquatic life.

Issues: Issues concerning time differentiation pertain to the hours or months used to define the peak period. There is little disagreement over time-differentiated pricing, as it is recognized as an effective load-management tool. It is beneficial to consumers who can operate on off-peak periods, for example, irrigators and some industry. It is also beneficial as a pricing signal to consumers, and may promote avoidance or delay of future expensive generation construction and operation with attendant environmental impacts.

Beginning with this rate period, the winter peak capacity period has been redefined to include December through April. May is no longer considered to contribute to the relative probability of load loss because of the effect of the Water Budget during the period of April 15 to June 15. These provisions of the Water Budget require a greater amount of water to be held in reserve for later release to assist the downstream migration of fish which will take place primarily during the month of May. This results in an increase in the expected available generation capacity of the hydro system during May in comparison with prior years. Therefore, incremental capacity requirements would be less likely to cause load loss during May than during the December to April period.

The transmission costs identified in the COSA and assigned to Federal power are classified entirely to capacity. These are costs incurred to strengthen the transmission system to accommodate loads and resources. Since the primary consideration for design of transmission reinforcement capacity is the peak hour of the year, all transmission costs could be assigned to the winter peak season for generation. However, ambient temperature affects transmission resistivity so that system load-carrying capability is systematically above average in the winter and less than average in the summer. After adjusting for the effects of temperature, no significant seasonal differentiation in the need for transmission capacity is discernable (See BPA, 1983a, p. F-4), therefore transmission costs are not seasonally differentiated.

Alternatives: There are two alternatives to consider in time differentiation: (1) combining thermal and hydro seasonal differentiation and (2) differentiating seasonal capacity costs using a methodology other than the probability of negative margin. Neither one of these is an alternative to the general concept of price differentiating based on some time period. Rather, they are alternatives to the basis for selection of time periods and for determining the appropriate degree of price differentiation.

A decision to change the basis for the time differentiation may change the designation of the periods. For the seasonal differentiation there may be shifts in the months and for the diurnal differentiation there may be shifts in the hours. The effect of these shifts on the customers will depend on the amount of the pricing differential between peak and off-peak and the ability of the consumer to respond to the price signal. The ability of consumers to respond can depend on constraints such as labor agreements, type of production, technology and size of firm. Generally speaking, high annual load factor consumers, operating 24 hours a day throughout the year, will not respond to seasonal or diurnal pricing differentials.

The consequence of any load shift on BPA would depend on the degree of consumer price responsiveness to the time differentiation. A wholesale power rate design will affect the final consumer only to the extent that it is passed on by a complimentary retail rate design. Therefore, it is not possible to reliably predict the effects of wholesale time-differentiated rates at the retail level.

d. Allocation of Costs to Customer Classes

When costs have been functionalized, classified, and time differentiated, they are allocated to customer classes in the COSA based on some measure (allocation factor) of the use of the power system by each customer class. The Regional Act establishes priorities of service from the resource pools to the rate pools. In order to determine what portion of costs of a resource pool will be allocated to a rate pool, load/resource balances are developed.

To examine this process of assigning costs to customer classes, it is first necessary to understand the relationship between customers (loads) and available electricity (resources). BPA has planned for the availability of resources to serve projected firm loads. There are three categories of resources; FBS, Exchange, and New Resources. Within each category are individual generation resources. When combined, these individual resources become "pools" of available resources. Section 7 of the Regional Act specifies the recovery of costs of these resources pools through rate directives for three distinct categories of customers: preference, DSI, and all other firm power customers. (See also I.A.1.)

The size of the resource pools is determined by the amount of available resource. The size of the FBS pool is a critical issue in determining rates, as the per-unit cost of power from this pool is the lowest because it consists primarily of low-cost hydroelectric projects. If the FBS is not large enough to meet projected firm loads, the second resource pool used is the Exchange. The Exchange resource pool consists of electric power which BPA purchases from the region's publicly owned and investor owned utilities who have entered into exchange agreements with BPA for the direct benefit of their residential and small farm consumers. The unit cost of power from this pool is higher than the FBS. The last category of resources available to meet load unable to be served by the FBS is the New Resource pool which includes all new resources developed, purchased or otherwise acquired by BPA that are not identified as FBS. The per unit power cost from this pool is higher than for either the FBS or Exchange pools.

The Regional Act directs BPA to establish rates for preference customers which will recover the costs of that portion of the FBS resources needed to supply their loads. When the loads of these customers exceed the resources of the FBS, the rates will recover the cost of additional electric power needed to serve their loads. The additional electric power will be provided first from the Exchange resources and then from New resources.

The Regional Act also directs BPA to establish rates to recover resource costs for the firm power requirements of the DSI's. After serving the preference customers, if FBS resources are insufficient to serve the DSI's; Exchange resources, followed by New resources, will be used.

Finally, the Regional Act directs the establishment of rates to recover resource costs for all other firm power sold by BPA for use in the region. After serving preference customer and DSI firm load, remaining Exchange resources and then New resources will be used.

Referring to the sample load/resource balance figure (Figure IV-4); it can be seen how changes, particularly changes in FBS resources, can shift costs between rate pools. For example, the Water Budget, described in section I.A., decreases the size of the FBS, resulting in the greater use of higher cost Exchange resources to serve the preference customer rate pool. Since the cost of the additional Exchange resource would have to be recovered, the rate would increase somewhat. As another example, an addition to the size of the preference customer rate pool, such as would occur if a new IOU wanted to participate in the exchange, would mean that more higher cost Exchange resources would be needed to serve the expanded customer class. Since the cost of the additional Exchange resources would be melded with the FBS resource costs, the per unit cost of resources to serve the entire preference customer rate pool would increase. Also, with the shift in the Exchange resource pool, it is possible that some high-cost new resources could be needed to serve the DSI's, thereby also increasing the per-unit cost to that rate pool.

FIGURE IV-4
LOAD/RESOURCE BALANCE

Rate Pools	Preference	DSI	Other Firm	Surplus Firm
Resource Pools	FBS	Exchange		New

The last example would also expand the Exchange resource pool, potentially affecting assignment of costs to other rate pools. Whether this increase in Exchange resources would counteract the shift in resources to serve the DSI's would depend on the relative sizes of the resource pools.

Through this process of balancing loads and resources, BPA can make several determinations. It can be determined if total resources will cover total loads. Also, the relative sizes of the resource pools can be matched with the rate pools for the purposes of cost allocation in accordance with the priorities of service as prescribed by the Regional Act. Finally, allocation of Federal and exchange transmission costs can be determined.

Generation energy costs (winter and summer) are allocated to customer classes according to whether such costs can be identified with resource pools. If costs cannot be linked specifically with a resource pool, such costs are allocated to customer classes in direct proportion to total energy loads placed on BPA by all customer classes, or in the case of conservation costs, by another method to be described later. Because the Regional Act established priorities of service from the resource pools to the rate pools, costs that are specifically identifiable with the energy production of the resource pools are allocated on the basis of the amount of energy service to each rate pool. Because energy loads and resources balance, the seasonal energy costs of each resource pool can be fully allocated.

Generation capacity costs are allocated in a manner similar to the allocation of generation energy costs. A substantial difference exists, however, in the method used for developing seasonal

capacity load/resource balances. Whereas energy load/resource balances can be developed by assuming that the Federal hydro system is operated in a way which balances energy loads and resources, the same assumption cannot be made for purposes of balancing capacity loads and resources. The amount of available resource pool capacity in the short run is fixed, and it exceeds the amount required to serve loads. Therefore, in order to allocate costs, the COSA scales down the Federal capacity resources so as to equal total capacity loads. It does this by assuming that the amount of excess resource capacity is from Federal resources only. Therefore, exchange resources and loads are excluded from the balancing of capacity loads and resources. (Refer to the COSA (BPA, 1983a) for the data and development of this approach.) When seasonal capacity loads and resources are in balance, the method for development of allocation factors for capacity is identical to that used to develop energy allocation factors.

Conservation costs are not resource pool related costs, and are therefore not allocated by use of methods described above. BPA allocates conservation costs on the basis of benefits received from conservation savings. Long-run benefits of conservation activities accrue to both BPA ratepayers and to ratepayers in the Region as a whole, regardless of whether or not they purchase power from BPA.

BPA ratepayers benefit from conservation savings by reductions in BPA's need to purchase additional and expensive resources. If conservation savings are achieved, BPA could avoid such expenditures. Such avoided costs represent a direct benefit to all BPA ratepayers. Some of this benefit is offset by the amount of revenue BPA would have received from additional sales of power that would have been made if conservation had not been achieved. The net benefit to BPA's ratepayers is the avoided cost minus the lost sales revenue.

Total conservation costs are divided into two portions. One portion, corresponding to the portion of benefits allocable to BPA ratepayers, is assigned directly to BPA loads which are deemed to be served by Federal resources (FBS and New resources). Loads deemed to be served by Exchange resources are not allocated any of this portion of conservation costs because conservation costs are already included in Exchange resource costs. The other portion of the conservation costs, is equated with the benefits for conservation accruing to the region as a whole. BPA allocates this portion of conservation costs to all regional energy loads. (See BPA, 1983a, Appendix G).

The following criteria were used in selecting the methodology for allocating conservation costs. The method should equitably recover costs from utilities that do not purchase all of their power from BPA, as well as from those that do. Exchanging utilities who deem their average system cost equal to the Priority Firm rate should be treated equitably with nonexchanging utilities. Loads served by Exchange resources pay a portion of the conservation costs included in each exchanging utility's average system cost. The method should consider that fact when allocating conservation costs to BPA loads served by the Exchange resource pool. The method should deal with lack of certainty of recovery of costs allocated to the New resources and Surplus Power rates. Loads served by New resources and customers purchasing surplus power could logically be allocated a large portion of conservation

costs because the conservation savings permit them to avoid purchase of marginal resources. However, it is important that the conservation costs allocated to these classes not be so great as to render the power unmarketable. The method should not be a major disincentive for utilities to participate in BPA's conservation programs. The method should not provide preference agencies with an incentive to participate in the residential exchange.

Issues: The inclusion of certain loads is an issue in arriving at a load/resource balance. The principle allocation issues relate to the allocation of generation capacity costs and energy conservation costs. The generation capacity issues pertain to the method of assigning resource pool costs to the rate pools; particularly the costs of excess resource capacity.

The issue regarding energy conservation costs pertains to the selection of an acceptable allocation method. In the 1981 rate filing, conservation costs were allocated to the FBS and New resources pools in proportion to the energy savings estimated for the preference agencies and IOU's, respectively. In the 1982 rate filing, conservation costs were allocated across all BPA loads. The method in the current filing (Marginal Minus Average method) is designed so that conservation costs are borne by those who benefit, including loads served by BPA and loads served by others.

A second issue pertaining to energy conservation costs is the use of a contract charge in the cost allocation methodology. A contract charge is seen as a disincentive to utility participation in BPA's conservation programs.

Alternatives: There are five sets of alternatives in this section. The first set concerns alternative loads and resources; the second set concerns the composition of surplus firm capacity; the third set involves allocation of surplus firm capacity costs; the fourth set pertains to conservation costs, and the fifth set looks at methods for determining the size of the surplus.

Alternative Loads and Resources: There are three alternatives under consideration in this rate period which would cause a shift in the cost allocation between rate pools. The effects of these alternatives can be analyzed with the load/resource balance table. These alternatives are (1) excluding Alumax from the DSI load; (2) excluding the loads of "deemers" from the exchange; and (3) using a sale of surplus firm power to replace a capacity/energy exchange agreement.

Alumax is a planned but not constructed aluminum plant. The company signed a contract with the BPA thereby placing an obligation on BPA to have resources available to serve Alumax's load whenever the plant began operations. In the 1983 initial proposal, Alumax loads are included, therefore expanding the DSI rate pool. The fact that the DSI pool is larger means that the amount of firm power which can be declared as "surplus" to the needs of the rate pools is smaller. Surplus firm power can be marketed but it is possible that not all of its allocated costs will be recovered. A portion of the forecast OY 1985 surplus consists of Exchange resources. In accordance

with the Regional Act, unrecovered exchange resource costs are assigned to the DSI's. The fact that the surplus resource pool is smaller means that the potential for unrecovered costs assignable to the DSI's is lessened.

Alumax has made public a statement indicating that they are indefinitely delaying plans to construct the aluminum smelter. Therefore, even though the contractual obligation on BPA remains, there is some reason to exclude Alumax in the balancing of loads and resources. Removing Alumax from the DSI loads has the following effects: (1) the DSI rate pool shrinks; (2) the amount of surplus firm power increases; and (3) the potential for unrecovered surplus exchange costs assignable to the DSI's increases.

Simply described, "Deemers" are utilities which are eligible to participate in the residential exchange but no exchange of power actually takes place during the rate period. Because deemers can elect to participate in the exchange, they have been included in the Exchange resource pool and the preference customer rate pool. However, since deemers by definition have not exchanged power, there is reason to exclude them in the balancing of loads and resources. Removing the deemers from the Exchange resource pool means that (1) the Exchange resource pool would shrink, and (2) the potential for unrecovered surplus exchange costs assignable to the DSI's lessens. Carrying the effect even further, if the Exchange pool shrinks to the point that some New Resources need to be used to serve DSI loads, there could be a counterbalancing increase in resource costs assigned to the DSI rate pool for recovery.

Removing the deemers from the preference customer rate pool could mean fewer higher-cost Exchange resources would be needed to serve the smaller rate pool. This could decrease the per-unit cost of resources to serve the entire rate pool.

The last of the set of alternative loads and resources is the replacement of a capacity/energy exchange agreement with a sale of surplus firm power. Under the capacity/energy exchange agreement, BPA generates capacity for a customer and that customer is usually obligated to return both the energy associated with the delivery of capacity and additional energy as payment for the capacity. Such exchange energy is included as an FBS resource and has the effect of lowering the unit FBS costs. The effect of replacing such an agreement with a surplus firm power sale would be to (1) reduce the firm surplus and the revenue underrecovery from surplus firm power sales; (2) reduce the size and increase the unit cost of FBS energy resources; and (3) decrease the unit cost of FBS capacity. Absent any adjustment, the DSI rate would likely be lowered because of the reduction in the revenue underrecovery from surplus firm power sales. The net effect on the rate to the preference customers is unclear because of the interaction of the effects.

Alternative Composition of Surplus Firm Capacity: A second set of alternative methods pertain to the allocation of capacity costs and center principally on the composition of surplus firm capacity resources and the allocation of associated costs. The source of the surplus firm capacity is not traceable to specific resources; therefore, there are alternative ways to define the surplus which have different cost implications.

Surplus firm capacity could be defined to come either from all resources or from FBS resources only. If surplus firm capacity is defined as coming from FBS resources only, the implication is that Exchange resources do not contribute to the excess. The difference between these two alternative definitions is in the total cost of surplus resources which must be recovered. FBS resources are less expensive. Unrecovered costs based on FBS only would be a lesser amount and would therefore have less impact to the rate pools. Excluding Exchange resources as contributing to excess capacity also decreases the costs assignable to the DSI rate pool.

Alternative Allocation of Surplus Firm Capacity Costs:

The third set of alternatives involves the allocation of generation capacity costs, particularly excess capacity costs. These costs could be allocated (1) uniformly to all customers classes; (2) to the rate pools on the basis of energy received from the resource pools; (3) based on capacity loads and assuming all excess capacity could be sold; (4) based on capacity loads assigning excess costs to the rate pools based on their load relative to total loads; and (5) scaling down capacity resources and assuming the excess is attributable to all resource pools.

A uniform allocation of all capacity costs to customer classes could be used. This would be achieved by dividing total capacity costs (including costs associated with surplus resources) by total capacity loads. This method would be simple to implement, however, it would tend to destroy the identity of the rate pools.

Capacity costs could be allocated to the rate pools on the basis of energy received from the resource pools. This method requires only that energy loads and resources be quantified, and an energy load/resource balance be prepared to identify the portion of each rate pool's load served by each resource pool. Capacity costs would be allocated in those proportions developed by an examination of the energy availability from the resource pools. This method assumes that capacity and energy requirements of the rate pools are met by the resource pools in a directly proportional basis. This is not realistic, however, as there are resources and classes of service with which either energy or capacity, but not both, are associated.

Available capacity from the resource pools could be quantified and compared to capacity loads. Capacity available from the resource pools could be assigned to the rate pools on the basis of the cost recovery priorities of Section 7(b)(1) of the Regional Act. Any resource pool capacity in excess of total loads then could be assumed to be sold independently to recover the costs of the excess. The excess capacity that is assumed to be sold under this methodology is BPA's highest cost capacity. There is little expectation that BPA can sell this excess capacity at its fully allocated cost. An inability to sell this excess would result in underrecovery of costs.

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

of excess capacity that would be allocated to the rate pools are a melding of Exchange resource and New resources cost. BPA has agreed to enter into a settlement with its customers with respect to its Power Sales Contracts litigation. One of the provisions of this settlement is that no unrecovered cost of the Exchange resources will be allocated to the preference customers purchasing from the 7(b) rate pool. Adopting this method may be in violation of this settlement provision.

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

Because capacity loads and resources are not normally planned to precisely balance, it is necessary to examine the origins of the excess capacity. BPA plans acquisition of resources primarily to provide energy for the region. In the course of acquiring energy resources, capacity resources also are added, frequently in excess of the added capacity loads. BPA is unable, however, to rigorously trace the origins of excess capacity to each individual resource pool because the nature and amount of the excess are not easily determined.

Alternative Allocation of Conservation Costs: The fourth set of alternatives pertains to the allocation of conservation costs and the use of a contract charge to recover a portion of conservation costs. The principle conservation cost allocation alternative is the Cost Follows Benefits method. This method compares BPA rates under two scenarios: (1) assuming no conservation costs or savings, with additional loads served by incremental cost resources, and (2) assuming conservation load savings, but no conservation costs. The conservation costs would then be allocated so that all rates would be raised from those developed in scenario 2 by an equal percentage based on a comparison between the two scenarios. The Cost Follows Benefits method is solely a methodology for allocating costs assigned to BPA rates. It quantifies only short-term benefits to BPA rate pools and ignores long term benefits and the benefits to loads not served by BPA.

Another conservation cost allocation alternative method is to combine the Cost Follows Benefits method with another method, such as Costs Follow Regional Loads. The result would recognize and approximate regional and long term benefits. Combining these methodologies, however, is complicated and has potential for controversy because of the assumptions needed to complete the analysis.

The inclusion of a contract charge in the conservation cost allocation methodology in the 1982 rate filing was seen as a disincentive to utility participation in BPA's conservation programs. Conservation results in a reduction of loads. If a utility has high fixed costs, this reduction in load would cause a decrease in revenues. The conserving utilities would then have to increase their retail rates.

For this rate filing BPA still concludes that a contract charge as a mechanism to recover costs outside of rates is required. The charge is relatively small and should not serve as a disincentive to participate in BPA's conservation programs.

Alternative Methods For Determining the Size of the Surplus: The fifth set of alternatives concerns alternate methods of determining the amount of BPA's surplus firm resources during the rate period. In the initial proposal, BPA assumed the hydrosystem would be operated in a manner which would effectively levelize, or uniform, the size of the surplus over the critical period. This assumption resulted in an estimated surplus of 730 average megawatts during the rate period.

Under an alternate method, the size of the firm surplus could have been estimated based on the first year surplus assuming that hydro operations would not be constrained to keep surpluses uniform over the critical period. Under this assumption, BPA's expected loads and resources over the next few years would result in a larger firm surplus at the beginning of the period, with fewer surplus resources toward the end of the period as firm loads increase.

BPA analyzed the effects of the first year surplus assumptions on cost allocations and rate levels among customer groups. Based on recent load and resource forecast data, the firm surplus for the rate period using first year surplus assumptions would be 1623 average megawatts, 893 average megawatts greater than under initial proposal assumptions (PNUCC, 1982). The first year surplus alternative would result in more FBS resources, corresponding to the 893-average megawatt increase in the firm surplus. Therefore, costs assigned to the FBS would be spread over a greater amount of capacity and energy resources, resulting in lower unit costs for the capacity and energy components of the FBS. This decrease in FBS unit costs relative to the initial proposal would have a decreasing effect on the rate to priority firm customers, which are served with FBS resources. Furthermore, the lower priority firm rate would involve fewer total costs associated with the IOU and public agency exchange, with fewer exchange costs to be allocated among the customer groups.

The amount of excess revenues to be credited to the allocated costs of BPA's firm customers would be less under this alternative for two reasons, primarily. First, the level of the Nonfirm Standard rate, which accounts for a large share of excess revenues, would be somewhat lower primarily due to the larger size of the FBS. Second, the increased amount of surplus firm would compete with nonfirm energy in the surplus market, causing more nonfirm energy to be sold at the lower Spill rate.

The amount of underrecovery associated with Surplus Firm Power revenue deficiencies would be greater under the first year surplus alternative. In the initial proposal, BPA assumed that 335 average megawatts of surplus firm power would be sold at its fully allocated cost, while the remaining 395 average megawatts would be sold at a price below its fully allocated cost. The first year surplus alternative would result in an estimated additional 893 average megawatts of surplus firm power to be sold at less than its allocated cost, greatly increasing the amount of revenue deficiency. Since the majority of the unrecovered costs of surplus firm power

is allocated to the Industrial Firm customers, this increase in surplus firm power revenue deficiencies would have a significant increasing effect on the rate level to BPA's DSI customers.

In summary, BPA's analysis of this alternative indicates that the first year surplus assumption would result in generally lower rates to most of BPA's customer groups relative to the initial proposal, with the exception of the Industrial Firm customers. The average priority firm rate would be lower, due to the lower unit costs of energy and capacity associated with the larger FBS and the lower level of exchange costs. The lower exchange costs would also have a decreasing effect on the New Resources Firm and Surplus Firm Power rates. As stated above, the Nonfirm Energy Standard rate would also be somewhat lower, due to the increased size of the FBS. Meanwhile, the decrease in the amount of exchange costs borne by Industrial Firm customers under this alternative would be overridden by larger increases in unrecovered costs of surplus firm resources, resulting in a higher rate level to Industrial Firm customers.

Table IV-20 presents a summary of how BPA's major costs for the initial proposal have been functionalized, classified, and allocated.

2. Rate Design Adjustments

The following includes eight sections (Sections 2a through 2h) which describe the rate design adjustments made to the results of the cost allocation analysis (COSA) previously described. Some of the adjustments are made pursuant to the Regional Act (value of reserves, Low Density Discount, exchange cost, and Hanna Adjustment), while others simply reflect BPA's ratemaking policies (DSI top quartile pricing). Still others are the result of unalterable circumstances (revenue deficiencies resulting from fixed contracts and Surplus Firm Power sales) or of policy combined with marketing realities (excess revenue).

In addition to the cost adjustments there are a number of charges and adjustments (Sections 2i through 2k) applying to several rate schedules. A charge for unauthorized increase has traditionally been included in BPA's rates. In the 1982 rate filing, an Exchange Adjustment Clause was added to many of the schedules. For this rate filing, several changes have been made to enhance revenue stability. The Priority Firm, Industrial Firm, and New Resource Firm rate schedules have been modified to achieve greater revenue stability (customer charge and billing determinants). In addition, a Supply System Adjustment Clause has been added to enable BPA's rates to track changes in Supply System costs.

Finally, there are a number of adjustments and charges which apply primarily to only one rate schedule (Sections 2l through 2o). These are the application of the low density discount, the crediting of the value of reserves, and the sustained peaking surcharge. An alternative adjustment, the transformation charge, is analyzed. The components of the Nonfirm Energy rate are also analyzed.

Table IV-20

Summary of Percent Allocation of Major Costs
Based on 1983 Initial Proposal

Functionalized Costs	Percent Capacity (Differentiated: 21% summer, 79% winter)	Percent Energy (Differentiated: 33% summer, 67% winter)	Allocation Customer Class
Generation Costs:			
Federal Base System			
Hydro Peaking	100	-	
Hydro Base	73	27	
Fish & Wildlife	80	20	
Thermal	17	83	
Total FBS Generation	32	68	7b
Total New Resources	17	83	7f
Total Exchange Resources	38	62	7b, 7c, 7f
Net Energy Conservation	17	83	7b, 7f
Total Generation Costs	34	66	
Total Transmission Costs	100	-	
Total Costs Recovered Through Rates	47	53	

Source: BPA, 1982c (Table 4)

The rate design adjustments are summarized in a section. Following the summary section, three alternate rate structures (flat, declining block, and tiered rates) are analyzed (Section 2p).

The proposed rates also include a "scaling factor." This scaling factor is applied to all adjustable wholesale and transmission Period B rates in order to derive Period A rates. The factor accounts for the circumstances that while the rates are based on a test year of July 1, 1984, through June 30, 1985 (Period B), the effective period of the rates will begin on November 1, 1983. If the Period B rates were applied to the entire rate period, BPA would recover more revenue than required to meet the revenue requirement. (Refer to BPA, 1983g, for additional rate design information.)

a. Excess Revenue

The excess revenue adjustment credits dollars from five sources (NF-83 Nonfirm Energy sales, DSI top quartile pricing, Capacity/Energy Exchange, IS-83 Intertie South and ET-83 Energy Transmission transactions) against allocated costs. In general, excess revenue is generated when revenue exceeds allocated costs. If BPA did not adjust its allocated costs to reflect such revenue, more revenue would be collected than required to meet the repayment obligation. The excess revenue adjustment credits revenue from such sales to other customer classes, thus reducing the allocated costs so that BPA does not overcollect its revenue requirement.

Excess revenue allocated to FBS and New resources is credited to capacity and energy. BPA uses the crediting of excess revenue to bring the results of the COSA classification of embedded costs closer to the classification of costs in the TDLRIC Analysis. New resources costs are classified in the COSA using the generation percentages in the TDLRIC analysis (17 percent capacity and 83 percent energy). These same percentages are used to credit the excess revenue assigned to New resources. However, the COSA classification process results in a greater percentage of FBS costs classified to capacity than would be indicated by the results of the TDLRIC. Consequently, excess revenue assigned to FBS is credited using the reverse TDLRIC generation classification percentages (83 percent capacity and 17 percent energy). This results in rates which send a more accurate price signal concerning the relative incremental cost of capacity and energy.

For the test year 1985, BPA anticipates excess revenue of \$290.2 million. Sales at the proposed NF-83 Nonfirm Energy Standard and Spill rates (excluding Surplus Firm Power sales made under that rate) contribute \$226.0 million to this total and DSI top quartile pricing contributes \$44.0 million. The major sources of excess revenue and the excess revenue allocation process are discussed individually below.

Nonfirm Energy Sales: To determine the amount of excess revenue from Nonfirm Energy sales, BPA forecasts the sales made and revenue received under the NF-83 Standard, Spill, and Displacement rates, and the EB-83 Energy Broker rate for the test period. The excess revenue is allocated to FBS and New resources.

DSI Top Quartile: The second major source of revenue credited to FBS and New resources results from costs assigned to the top quartile of the DSI load under the proposed Industrial Firm Power rate, IP-83. BPA does not assign generation costs to top quartile service in the COSA since resources are not planned or acquired to serve this load. Instead, an opportunity cost methodology is used to determine the costs associated with serving top quartile load. BPA uses the generation portion of the average monthly nonfirm rate and the NF-83 Spill rate to assign an opportunity cost to top quartile service. These rates were selected as best approximating the opportunity cost of this service given current market conditions. An amount equal to the total opportunity cost, \$44.0 million, is then credited to FBS and New resources.

Capacity/Energy Exchange: BPA may request that a customer pay 3.0 mills per kilowatthour in lieu of the return of energy under the Capacity/Energy Exchange contracts. BPA forecasts that 96 average megawatts will be displaced with these cash payments. Thus, the Capacity/Energy Exchange will produce \$2.5 million in revenue. Since energy returned to BPA under Capacity/Energy Exchange contracts is deemed an FBS resource, revenue received when BPA does not require the return energy is credited to FBS.

Issue: The principle issue concerning the crediting of excess revenue is the division of the credits between capacity and energy.

Alternative: BPA credits the FBS assignment of excess revenues using the reverse TDLRIC percentage, resulting in rates which send a more accurate price signal concerning the relative incremental cost of capacity and energy. An alternative FBS excess revenues credit is to base the assignment on the same classification percentages developed in the TDLRIC (17 percent to capacity and 83 percent to energy). This methodology would lower the priority firm energy charge and presumably lower the anticipated bill of energy intensive, high annual load factor industry. However, this alternative would not recognize the economic tradeoff between FBS capacity and energy and would result in rates giving a less accurate price signal.

b. Revenue Deficiencies

Certain customers receive services from BPA at contract rates that are fixed. The two categories of these fixed rate contracts are Canadian Treaty and Capacity/Energy Exchange. These contractual arrangements increase both the capacity and energy of the Federal system. The costs allocated to the Canadian Treaty and Capacity/Energy Exchange, however, exceed the revenue that can be collected under the contracts. Therefore, if the costs to be recovered from other services were not adjusted accordingly, BPA would be unable to meet its revenue requirement. To remedy this situation, BPA apportions the revenue deficiency (adjusted for the assignment of excess revenue from sales of Nonfirm Energy), to the classes of service for which rates can be changed and by which the benefits of the added FBS capacity and energy are received.

The total Canadian Treaty and Capacity/Energy Exchange deficiency, adjusted for revenue from sales of Nonfirm Energy, is approximately \$79.0 million. Of this total, \$20.7 million is classified to capacity and \$58.3 million is classified to energy.

Canadian/Treaty: When the "Treaty between the United States of America and Canada Relating to the Cooperative Development of the Water Resources of the Columbia River Basin" was ratified, BPA entered into obligations to generate and transmit capacity and energy to Canadian delivery points. Contracts resulting from this treaty require BPA to generate Supplemental and Entitlement capacity at a fixed rate of \$5.50 per kilowatt-year and to transmit Supplemental capacity and Columbia Storage Power Exchange (CSPE) power at a fixed rate of \$1.50 per kilowatt-year. These rates are fixed, but the amount of power to be provided gradually declines until April 1, 2003, at which time the contracts expire.

The Canadian Treaty resulted in an increase in the firm capacity and energy capability of the FBS. Power sales customers served by FBS resources, in turn, benefit from this increased capability. Therefore, the revenue deficiency associated with the Canadian Treaty is assigned to all capacity and energy sales customers served by FBS resources.

Capacity/Energy Exchange: The Capacity/Energy Exchange contracts obligate BPA to provide a service for which the contracting party often provides a reciprocal service instead of a direct payment. Under these contracts, BPA generates capacity when requested by a contracting customer and that customer is obligated to return both the energy associated with the delivered capacity and additional energy as payment for the capacity. When BPA does not require the return of the energy (for example, under high streamflow conditions), the contracting customer is allowed to pay for its obligation in cash at the contractually fixed rate of 3.0 mills per kilowatthour. In an average water year, a portion of the contracting customer's obligation is required to be returned while the remaining portion is to be paid for at the contractual rate. Such exchange energy is included as an FBS resource and has the effect of lowering the unit FBS costs. Therefore, the costs allocated to this class are assigned to the FBS.

Issue: The principle issue concerning revenue deficiencies is the assignment of costs.

Alternative: BPA assigns the revenue deficiency to the classes of service for which rates can be changed and for which the benefits of the added FBS capacity and energy are received. An alternative would be to allocate the deficiency uniformly across all customer classes. This would reduce the deficiency allocation to FBS customers and therefore reduce the costs to be recovered from that class. However, the benefits from the Canadian Treaty and capacity/energy exchange are directly conferred on the users of the FBS resources and the costs should follow the benefits.

c. DSI Top Quartile

Since BPA does not plan or acquire resources to serve the top quartile, only transmission costs are allocated to this portion of the DSI load in the COSA. Generation costs are assigned to the top quartile in the rate design study according to the opportunity cost of providing that service. Two methods are available for serving the top quartile: one using a combination of provisional drafts and nonfirm, the other using surplus Firm Energy Load Carrying Capability (FELCC). The DSI's have the option of selecting the service to their top quartile.

The provisional drafts (shifted FELCC, flexibility and advance service) use the flexibility of the hydro system to move water forward in time. In return for provisional service, BPA gains later additional restriction rights to protect service to firm loads. The short run opportunity cost of providing this service is equal to the revenue BPA could receive from sales if the water were not moved forward in time. Most of these sales would occur during the spring runoff and would be sold at the NF-83 Spill rate. The long run opportunity cost of service with provisional drafts would factor in the additional revenue available from providing or enhancing other services with the provisional drafts. Given the regional surplus, it is unlikely that the demand for such services would be great enough to drive the opportunity cost above the Spill rate. Therefore, the opportunity cost of providing service to the top quartile with provisional drafts is approximated by costing the service at the generation portion of the NF-83 Spill rate. This cost best approximates the opportunity cost of this service given the present market conditions.

The opportunity cost associated with the nonfirm portion of service to the DSI top quartile load was calculated by applying the generation portion of the monthly average nonfirm rate to the corresponding forecasted top quartile service. This approach approximates the projected revenue BPA could have received if the Nonfirm Energy had been sold in the market, rather than used to serve the DSI load.

For service provided by surplus FELCC, the opportunity cost reflects the firm nature of service to the top quartile load with firm resources. The cost assigned is the same unit cost as that assigned to the lower three quartiles of service. Service to the lower three quartiles is based on BPA's cost of serving the industrial load with firm exchange resources.

Issues: Issues with serving the DSI top quartile pertain to alternative methods of assigning costs for that service. At issue also is the DSI's option of selecting the form of service.

Alternatives: The DSI's have the option of selecting the source of their first quartile service. It can come from nonfirm energy and provisional drafts, or from firm surplus FELCC. The service with firm surplus FELCC is a higher rate option; therefore, the other service option is most often selected. The effect of this selection, during a period of unsold surplus, is to provide the DSI's with firm surplus at the less expensive nonfirm rate. This leaves BPA with more surplus firm energy than is currently marketable at fully allocated costs. An alternative would be to restrict the selection option in times of unsold surplus firm.

BPA uses an opportunity-cost concept to assign costs to the DSI top quartile service. There are alternatives pertaining to the costs on which to base the opportunity cost. For example, the opportunity cost associated with the nonfirm portion of service to the top quartile could be based on the energy costs of the actual resources used to serve the top quartile. Nonfirm service could be priced as was nonfirm energy under BPA's NF-1 rate (implemented in 1981) which reflected a combination of the cost of transmission plus an adder dependent on the cost of resources used to provide

nonfirm energy. However, this alternative would not necessarily represent the revenue BPA would have received from other markets if that energy were not delivered to the first quartile.

BPA currently uses an opportunity-cost concept for pricing the top quartile when service is provided by nonfirm energy or provisional drafts. However, when service is provided by surplus FELCC, BPA bases the price on the actual cost of firm resources. Use of the opportunity-cost concept to price service with surplus FELCC would be an alternative to the current method. However, in times when surplus firm energy is unsold, the resulting opportunity cost associated with the revenue BPA would have received from other markets would approach or equal zero.

d. Value of Reserves

Power sales contracts with the DSI's grant BPA the right to restrict the DSI loads under certain conditions. As a result, the Federal system can use these restriction rights as part of its reserve requirement. A value of reserves analysis is performed to measure the benefit resulting from the ability to restrict the DSI load and to comply with section 7(c)(3) of the Regional Act. The Federal system reserves provided by the DSI restriction rights are separated into forced outage reserves, stability reserves, and plant delay reserves. This separation follows the language of section (7) of the DSI power sales contracts. The resulting revenue deficiency is allocated to firm power classes of service.

Issue: There are two sets of issues with the value of reserves. The first pertains to alternatives to the classification of the revenue deficiency caused by the credit. The second set pertains to measurement of the benefits of the reserves and this is analyzed in Section 2m.

Alternatives: The revenue deficiency caused by the value of reserves credit is allocated to all firm power classes of service and classified according to the classification percentages developed in the TDLRIC Analysis. Alternative methods include classifying the deficiency (1) based on the overall COSA classification; (2) primarily to capacity; or (3) primarily to energy. None of these alternatives take into account the incremental cost relationships of capacity and energy as does the TDLRIC method.

e. Low Density Discount (LDD)

The Low Density Discount (LDD) is a discount applied to the Priority Firm Power bills of utility customers with low system densities. The LDD is made available pursuant to section 7(d)(1) of the Regional Act. The purpose of this discount is to help offset adverse effects on the retail rates of rural customers who have high distribution costs due to low system density, difficult terrain, remote service areas and/or other factors. The amount of the discount may be three, five, or seven percent depending on the characteristics of the utility. The revenue deficiency that results from granting the discount is allocated to the priority firm customer class.

Issues: The issues relating to the LDD pertain to the allocation of the revenue deficiency. A second set of issues pertaining to eligibility and measurement of the LDD is discussed in Section 2.k.

Alternatives: One alternative is to classify the deficiency caused by the LDD to capacity only, because the discount is related to fixed dispersal costs. While it is true that most of the costs related to dispersed systems are fixed costs, the LDD should not result in a change in priority firm classification percentages. Since the LDD is applied to both the capacity and energy charges uniformly, the deficiency should be classified similarly. Classification of the LDD deficiency to capacity would have the result of moving away from cost-based rates.

Another alternative is to allocate the cost of the LDD to all customers as is the Hanna discount. The Hanna discount is based on Hanna's use of raw materials indigenous to the region. Since the Hanna discount is justified on the basis of regional and national benefits, the cost was allocated to all BPA customers. The only beneficiaries of the LDD, on the other hand, are priority firm customers. Therefore, it is appropriate to allocate the LDD costs exclusively to that customer class.

f. Surplus Firm Power Revenue Deficiency

For ratemaking purposes, BPA has assumed for the initial proposal that it will be able to market 335 average annual megawatts of Surplus Firm Power at its fully allocated cost out of a total of 730 average annual megawatts of available Surplus Firm Power. The remaining 395 average annual megawatts will be sold at the NF-83 Nonfirm Energy rate for less than its fully allocated cost. BPA is differentiating between revenue from Nonfirm Energy sales resulting from Surplus Firm resources that cannot be sold at their fully allocated cost and revenue from Nonfirm Energy sales resulting from average water conditions (see Excess Revenue, Section a.). The resulting revenue deficiency of \$47.412 million is allocated to firm classes of service.

The allocation of the revenue deficiency is accomplished as follows: (1) Divide the revenue deficiency among New resources, Exchange resources, and adder (e.g., transmission, BPA overhead, rate design adjustments) pro rata based on the composition of Surplus Firm Power costs; (2) Allocate New resources and adder components to all firm sales; (3) Allocate Exchange resource component to the Industrial Firm Power class.

The New resources and adder components total \$5.501 million and are classified using the overall classification percentages of all resources, 35 percent capacity and 65 percent energy. The exchange resource component, \$41.911 million, is classified on the same basis as the total exchange resource, 38 percent capacity and 62 percent energy. The revenue deficiency is assigned to seasonal periods according to the time-differentiation percentages in the COSA and allocated to classes of service using COSA allocation factors.

Issues: Issues pertain to the classification and allocation of the revenue deficiency associated with unsold surplus firm power.

Alternatives: BPA allocates the cost of unsold surplus as stated above. An alternative is to use the unsold surplus to serve residential exchange loads rather than taking high-cost power from the exchanging utilities. This would reduce the amount of surplus firm.

Another alternative is to treat unsold surplus as nonfirm energy and add the cost of those resources to the nonfirm rate. This would mean that there would be no revenue deficiency associated with surplus firm.

An alternative allocation method is to allocate the cost of the unsold surplus to all customers rather than to only firm classes of service.

g. Equalization of Demand

Historically, BPA has had uniform demand charges for sales to Priority Firm, Industrial Firm, and Firm Capacity customers. Section 7(e) of the Regional Act acknowledges this tradition by enabling the Administrator to continue to set uniform demand charges.

To arrive at the equalized demand charge for Priority Firm and Firm Capacity sales, BPA sums, by component and for both classes of customers, the allocated costs for transmission, winter capacity, and summer capacity. BPA also sums the respective billing determinants and then divides each of the capacity components listed above by its respective billing determinant. The equalized demand charges for winter and summer capacity are calculated by adding the equalized transmission charge to the equalized winter and summer capacity charges.

Next, the Surplus Firm Power rate is assigned the same demand charge as the previously determined equalized charge. Any underrecovery of allocated capacity costs resulting from that assignment is handled by adjusting the level of the surplus firm energy charge. Thus, despite the equalization process, costs remain allocated to the appropriate customer class and are not shifted between classes. The New Resource Firm Power rate is also assigned the equalized Priority Firm demand charge.

Section 7(e) of the Regional Act allows BPA to equalize demand charges. This option facilitates administration of the rates and ensures that no customer has the incentive to purchase capacity and energy separately and thereby avoid a higher capacity charge in a power rate.

Issues: The issues pertaining to equalization of demand are whether it should be done.

Alternatives: An alternative to equalizing demand is not to do it. In the proposed equalizing process, firm capacity customers are treated as if they were a part of the 7(b) rate pool. However, the costs incurred to serve the capacity requirements of the customers purchasing firm capacity are lower than those for meeting the demand requirements of firm power customers. If rates were not equalized, the CF rate would be lower than the demand charges of other firm power rates. Therefore, customers might elect to purchase capacity under the CF-83 schedule in order to avoid the higher demand charges of the other rate schedules.

h. Hanna Adjustment

The Hanna Nickel Smelting Company (Hanna) applied for and was awarded a special industrial rate in the 1982 wholesale power rate filing pursuant to section 7(d)(2) of the Regional Act. Section 7(d)(2) provides for the special rate "in order to avoid adverse impacts of increased rates pursuant to this Act" for specified direct service industrial customers. For this rate proposal, it was assumed that Hanna would reapply and meet the eligibility conditions. The rate for Hanna, the IH-83 Special Industrial rate, equals the Priority Firm (PF-83) rate less the value of reserves. The rate approximates the rate that Hanna would have paid without the Regional Act.

A revenue deficiency is caused by charging Hanna the PF-83 rather than the IP-83 rate. This amount, \$1.9 million, is classified 17 percent to capacity and 83 percent to energy (the generation classification percentages developed in the TDLRIC Analysis). Since the Special Industrial rate is a form of rate relief which will benefit the whole region as well as the rest of the United States by increasing the probability that Hanna will be able to resume operations, the adjustment is allocated to all customers.

Issues: The issue relating to the Hanna adjustment pertains to the allocation of the revenue deficiency.

Alternatives: BPA has allocated the revenue underrecovery, caused by giving Hanna a special rate, to all customers. An alternative is to allocate the adjustment only to the DSI's, as the adjustment is designed to benefit a member of that specific customer class. Some customers have reasoned that this would be consistent with the allocation of the costs of the low-density discount (see Section 2e).

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

i. Revenue Stability

BPA has recently experienced a significant underrecovery of revenue from two types of customers: DSI's and computed requirements purchasers. In order to enhance revenue stability, a customer charge has been added to the IP-83 rate structure and the billing determinants for computed

requirements purchasers (in both the PF-83 and the NR-83 rate schedules) have been modified to reflect the costs which BPA incurs in being ready to serve a specified load.

Depending on market conditions, computed requirements customers have found it advantageous to (1) displace their firm purchases from BPA with their own nonfirm energy when the market price for nonfirm energy is low; (2) displace firm purchases from BPA with nonfirm energy purchased from other utilities; or (3) purchase BPA firm power and sell their nonfirm energy when the market price is favorable; i.e., higher than the Priority Firm rate. The customers have been able to choose to displace power from BPA without incurring any additional cost or charge. This leaves BPA with resources which were purchased to serve a load level which the computed requirements customers said they would need.

In earlier years, the displaced power could be marketed, except perhaps during extremely good water years, at a price equal to or greater than BPA's Priority Firm rate. Today, however, BPA is frequently unable to sell the displaced power at a rate that will recover BPA's fully allocated costs. Therefore, when power which BPA is obligated to provide is displaced, BPA faces revenue underrecovery.

Under the current 1982 rates, the computed requirements customers primarily paid only for the amount of power they took. The proposed 1983 rates have been changed so that the computed requirements customers will pay for the power they take plus a portion of the costs that BPA has incurred to meet their specified load level. This is done by weighting the proposed energy billing factor so as to reflect BPA's obligation to provide a given level of service under critical water conditions. This will compensate BPA for incurred costs, thereby ameliorating the problem of revenue underrecovery due to displacement. Since metered requirements customers currently pay for a portion of the costs associated with critical water planning for computed requirements purchasers, the new billing factors will more fairly distribute costs between computed requirements customers and those customers with fewer options under the power sales contract, i.e., metered requirements customers.

Issue: There are a number of alternative methods for promoting revenue stability.

Alternatives: BPA's main consideration is to increase revenue stability and minimize the displacement of BPA firm power. To achieve this, BPA has modified the billing determinants of the computed requirements customers and added a customer charge to the IP-83 rate structure. Alternatives to these two actions are discussed separately. Following the discussion of alternatives to these two actions is a section discussing the alternatives to achieve revenue stability including elimination of the spill rate and a deferral adjustment clause.

Alternatives to Modifying the Billing Factors:

Modification of the billing factors is being proposed in two rate schedules, the PF and the NR. An alternative is to charge computed requirements customers on a "take or pay" basis. This would mean that the customer would be charged for the amount of firm power they requested BPA to have available to serve them, whether or not they used the power. However, it

is possible that BPA could receive some revenue from the sale of the displaced energy in the nonfirm market. However, it is likely that the additional revenue from such nonfirm sales will be less than the revenue BPA would have received from the firm power sales. Therefore, BPA is willing to share the risks of revenue underrecovery with the customers by modifying the billing determinants.

Alternatives to DSI Customer Charge: Under BPA's 1983 initial wholesale rate proposal, a customer charge would be included in the DSI rate. Remaining revenues would be collected from demand and energy charges which would vary with actual DSI operating levels. The total bill individual DSI's would face would be the same with or without a customer charge. However, since fewer revenues would need to be collected from demand and energy charges, those DSI's which choose to operate during the rate period would face lower incremental electricity costs than they would in the absence of a customer charge. However, if some DSI's could foresee actual operation only at low levels during the rate period, they may see the customer charge as being too high to economically justify operating at any level and cancel their contracts with BPA altogether.

One alternative to this proposed charge would be a mutually agreed "take or pay" rate option. This alternative would establish a rate level for a certain guaranteed level of load. Since the "take or pay" provision is mutually agreed upon, this alternative would benefit both BPA and the DSI's by providing the industries an incentive to operate and by improving BPA's revenue predictability.

This alternative has the potential for increasing BPA's revenues and revenue predictability and allowing for increased DSI operations at lower effective power rates if a sufficient guaranteed load level can be achieved through the "Rate B" arrangement. However, if sufficient DSI loads cannot be guaranteed under a "take or pay" concept, Rate A under this proposal would be in effect. In the absence of a customer charge, BPA's revenue would be more sensitive to deviations of actual DSI loads from forecast loads.

This alternative could be modified to include a customer charge under Rate A. The customer charge will guarantee a portion of the DSI class's revenue requirement if for some reason the optional rate (Rate B) is not selected.

Another modification could be for BPA to offer its rate option only for rate Period A (November 1, 1983, through June 30, 1984) with a later similar offer made for Period B (July 1, 1984, through June 30, 1985). This would give both BPA and the DSI's time to reassess their respective situations prior to Period B, allowing for flexibility for both BPA and the DSI's to adjust for trends during Period A, e.g., BPA revenue levels, prices for DSI products.

Another alternative method designed to ensure that BPA would collect at least a portion of the revenues forecast to be received from the DSI's is a minimum bill. A minimum monthly bill could be set to recover one-twelfth of the cost allocated to the lower three quartiles of customer contract demand. A minimum bill would impose an additional charge on top of the contractually imposed curtailment charge.

Other Alternatives for Achieving Revenue Stability: There are two other alternatives for improving BPA's revenue stability. With respect to the computed requirements customers, most displacement of firm purchases from BPA occurs when BPA is selling at the nonfirm energy Spill Rate. Therefore, elimination of the Spill Rate would be an alternative which could result in fewer displacements of firm purchases from BPA. However, a utility might base its decision regarding displacement on the average cost of power from BPA and not just on the marginal energy rate. Since the average cost of power probably would exceed the average nonfirm rate, displacement of firm purchases might still continue.

A second alternative to improve BPA's revenue stability is a Deferral Adjustment Clause. This clause would automatically adjust rates in response to large changes in revenues caused by events over which BPA has little control, such as weather or economic conditions.

j. Adjustment Clauses

An automatic adjustment clause allows rates to adjust automatically in response to changes in the actual costs of major expense items over which a utility usually has little control. The automatic nature of the adjustment clause allows for increases or decreases in rates, and thus a closer tracking of costs, without the delay and expense of formal rate hearings. Two automatic adjustment clauses are included in the proposed rates: the Exchange Adjustment Clause and the Supply System Adjustment Clause.

Exchange Adjustment Clause: An Exchange Adjustment Clause is included in the Priority Firm, Industrial Firm, Firm Capacity, New Resource Firm and Surplus Firm rate schedules because exchange resources are assigned to loads served under these rates. The adjustment is in the form of a rebate or surcharge if the actual average cost of selected exchange resources during the period November 1, 1983, through June 30, 1985, differs from that forecast. The actual average cost of exchange resources is based on the average cost of the five nondeemer IOU's. Any changes in the relative mix of the exchange load between exchanging utilities will affect the average cost of the exchange.

Issue: The issue on the exchange adjustment clause is the calculation of the average cost of the exchange.

Alternative: BPA's calculation for the actual average cost of the exchange is based on the average cost of five non-deemer IOU's. The alternative calculation would base the adjustment on an average of all costs of exchanging resources, including deemers. Since deemers may elect to exchange, this alternative would account for their costs. However, deemer IOU's have no impact on net revenue, and public agencies have only a minor impact because their average system costs are close to the Priority Firm rate.

Supply System Adjustment Clause: A Supply System Adjustment Clause has been included in the Priority Firm and Firm Capacity rate schedules which are served by Federal base system resources. The adjustment will be made to the Priority Firm Energy charges and the Firm Capacity rate effective July 1, 1984, to the extent that (1) the actual OY 1984 (July 1, 1983, through June 30, 1984) Supply System funding

requirement for Plants 1, 2, and 3 differs from the costs in the forecast revenue requirement for OY 1984, and (2) the OY 1985 Supply System Annual Budget for Plants 1, 2, and 3 differs from the costs in the forecast revenue requirement for the test year. The adjustment may be triggered only once and no final adjustment will be made.

Issues: The issues with the Supply System Adjustment Clause concern the costs which should be covered and the rate schedules to which the adjustment should apply. Also at issue is whether there should be any limit on the amount of the adjustment.

Alternatives: There are alternative ways to compute Supply System costs which could be covered by the proposed adjustment clause. The clause could limit the costs passed through the adjustment to changes in forecasted price of materials and exclude cost changes due to changes in the quantity of material required. However, limiting the adjustment to one component of the Supply System cost would not fully track BPA's obligations and could cause a potential revenue underrecovery.

Also, an issue is whether there should be an upper limit on the amount of the adjustment. An alternative 10-percent ceiling could be established on the increase in actual Supply System cost from forecasted costs that would pass through to BPA customers. Placing any limit on the amount of costs that can pass through to the customers could potentially hinder BPA's own ability to recover costs. This would cause revenue underrecovery, potentially causing increased deferral of payments due to the Treasury.

BPA proposes that the adjustment should apply to those customers allocated FBS costs (PF and CF rate schedules). An alternative is to also include the adjustment on the NF rate schedules as it is affected by FBS costs.

Other Adjustment Clauses: Another adjustment clause which has been considered is a low water surcharge. This would be an additional charge which would be applied to FBS customers contingent upon a system condition such as failure to refill a reservoir. Such a surcharge would reduce the cost of constructing and operating the system for hydrologic events with a low possibility of occurrence.

k. Low Density Discount (Application)

A Low Density Discount (LDD) was included in the PF-1 Priority Firm Power rate schedule pursuant to Section 7(d)(1) of the Regional Act. This discount was instituted to avoid adverse impacts on retail rates of utilities with low system densities. All customers purchasing priority firm power, both public and investor-owned, are eligible for the discount provided their systems meet the system density criteria established by BPA. (See Section 2e. for allocation of LDD).

BPA uses two ratios to calculate the discount: (1) total kilowatthour sales divided by total depreciated investment in electric plant (excluding generation plant); and (2) total residential consumers divided by pole miles of distribution line. BPA has had an upper limit of 10 consumers per mile to qualify for the LDD. BPA is also proposing a limitation for the

kilowatthour to investment in electric plant ratio of 60. The LDD affects the level of the Priority Firm rate, but does not impact the costs to be recovered from other customer classes.

In the initial proposal, BPA assumed that the average system cost for exchanging utilities would include the actual cost of power which the exchanging utility would be purchasing from BPA. That is, if the exchanging utility were entitled to an LDD, then the average cost of power purchased from BPA would be lower than the cost would have been without the LDD.

Issues: LDD issues concern the additional qualification limit on the ration of kilowatthours/investment in electric plant and the application of the LDD to exchange loads.

Alternatives: An alternative to the proposed limit of 60 kilowatthours per load is to have no limit. However, the purpose of the limits of 10 consumers per mile of pole line and 60 kilowatthours per investment is to screen out customers which are not typical of utilities with low system densities, the intended beneficiaries of this mitigation measure.

An alternative to BPA's proposal is to not grant an LDD on exchange purchases because it is contended that exchanging public agency utilities are thus awarded the discount twice--once on their exchange loads and once on their total loads.

The discount is, in effect, awarded twice. However, BPA purchases an amount of power from the exchanging utility equal to its exchange load. Thus, while the discount is awarded twice, it is in effect taken away once. It is true, however, that the dollar value of the discount is different if the discount is not applied to exchange power. This difference is due to the fact that whereas the utility purchases power from BPA at the utility's Priority Firm Rate, BPA purchases the exchange power from the utility at the utility's average system cost. Thus, in the case of Douglas Electric Coop, the amount of the discount would be \$219,920 if it were applied only "once," i.e., to its total load, but the total dollar value of the discount is \$170,290 greater if it is applied to exchange loads as well.

1. Value of Reserves Credit

The Federal system reserves provided by the DSI restriction rights are separated into forced outage reserves, stability reserves, and plant delay reserves.

Forced outage reserves maintain the operating integrity of the Federal system. To calculate the value of forced outage reserves, it was assumed that, absent the DSI restriction rights, the Federal forced outage reserves requirement would be met by installation of the least-cost alternative of 1880 megawatts of combined cycle combustion turbines. The annual cost associated with the turbines is \$125,210,000. However, this cost overstates the benefit derived from the DSI restriction rights. In test year 1985, the DSI's are estimated to provide 1245 Megawatts of forced outage

reserves, based on the size of the second and third quartiles of projected load. Thus, the investment cost was prorated based on the amount of reserves provided by the DSIs to derive the annual cost of \$82,918,000.

Stability reserves prevent regional and interregional instability resulting from underfrequency on the electrical grid. Stability reserves provided by the DSI restriction rights were valued at the cost of installing a load tripping scheme which would isolate various portions of the system in lieu of restricting. The annual cost in the test year associated with these reserves is \$64,000.

Plant delay reserves protect the reliability of the system from construction delay and poor performance of existing plants. The Pacific Northwest Systems Analysis Model (SAM) was used to calculate the probability of restricting the DSI's second quartile due to plant delay and the corresponding expected amount of the restriction. In lieu of restricting, BPA assumed the combined cycle combustion turbines would be run. BPA looked at the probability of restriction over a future 7-year period. The annual levelized cost associated with plant delay reserves provided by restricting the DSI's second quartile is \$72,000.

The total value of reserves provided by the DSI's restriction rights in the test year is \$83,880,000. To calculate the credit the DSI's receive, BPA employs a share-the-savings methodology. Added to the value of the reserves provided by the DSI's is the expected cost to the DSI's of the outages, \$126,000. This total amount was divided in half to arrive at the value, \$41,940,000, that is credited to the DSI's. The value of reserves credit results in a revenue deficiency which is classified 17 percent to capacity and 83 percent to energy according to the classification percentages developed in the TDLRIC Analysis.

Issues: The principle issue with the value of reserves relates to the level of the value.

Alternatives: An alternative calculation of plant delay reserves would include the acquisition of conservation as a resource the reserve would protect. This addition could considerably increase the value of plant delay reserves.

The DSI's receive a \$750,000 credit for stability reserves, a value based upon the cost of installing trippers which would create rotating blackouts in the region to avoid system failure. The value to other consumers of not having to face rolling blackouts is not recognized in the proposed calculation of the value of stability reserves. An alternative would be to include this value, thereby increasing the credit the DSI's receive.

The share-the-savings method for crediting the reserves results in the DSI's getting only one-half of the credit. An alternative is to pay full value for reserves.

m. Sustained Peaking Surcharge

To encourage capacity purchasers to limit their use of Federal generating facilities and maximize use of their own facilities, the CF

rate includes an additional monthly charge for capacity taken in excess of 9 consecutive hours per day.

Issue: The issue with the sustained peaking surcharge is the limit of 9 hours.

Alternative: An alternative is to allow sustained peaking for more than 9 hours. However, the 9-hour limit is based on the determination that taking of any additional hours of capacity could reduce system peaking capability.

n. Transformation

An adjustment under consideration is a transformation charge. This would be a separate charge to a customer for deliveries of power at lower voltages. BPA had a transformation charge during the 1974-1979 rate period. There is not currently a separate charge for transformation and that cost is combined with other demand costs and distributed among all firm power customers. However, the recent Exchange Transmission Credit Agreement provides transmission benefits to public agencies which would be eligible to exchange with BPA under the Residential Exchange Contract. Public agencies with existing low-cost generating resources receive no corresponding benefits for their transmission systems. A transformation charge would provide such a benefit.

o. Nonfirm Energy Rate

BPA plans generating resources sufficient to meet the forecast needs (firm loads) of its Pacific Northwest customers, assuming hydro conditions equal to the lowest water period of historical record for the Federal Columbia River Power System (FCRPS) (the hydroelectric power system of the Columbia River). If hydro conditions are better than this, more energy will be available to sell. The energy that is available under favorable water conditions is called nonfirm energy. Although nonfirm energy may be available at different times throughout the year, it is most plentiful in the spring and summer as a result of the increased streamflows that result from melting snowpack in the mountains and release of water to increase river flows for migrating fish. The FCRPS usually does not have the ability to store all of this water in reservoirs when it is most plentiful and BPA must generate energy or spill the water.

Utilities both inside and outside the Pacific Northwest can purchase nonfirm energy. Public Law 88-552 guarantees electric consumers in the Pacific Northwest first call on electric energy generated as Federal hydroelectric plants in the region. When Northwest utilities choose not to purchase this energy, under certain conditions it may be offered to customers outside the region. Therefore, nonfirm energy is offered first to Northwest utilities and then to utilities outside the Northwest at the same rate. BPA sales of nonfirm energy to California are limited by Intertie transmission capacity.

Revenue from nonfirm energy sales has reduced substantially the cost of electricity for Pacific Northwest customers. BPA credits the revenue received from nonfirm energy sales to its firm power rates.

(1) Standard Rate

The proposed Standard rate would apply when the FCRPS hydroelectric plants are neither spilling nor forecasted to spill due to an excess of energy on the FCRPS above available markets. The rate, 20.8 mills per kilowatthour in the test year, reflects the average cost of service with FBS and new resources power. Fifty percent of the energy sold under the Standard rate will be made available on a guaranteed delivery basis for 1 day.

(2) Spill Rate

The proposed Spill rate would be in effect when one or more FCRPS hydroelectric plants are spilling or are forecasted to spill due to an excess of energy on the FCRPS above available markets. The charge will be 13.0 mills per kilowatthour. This rate is based on an analysis of variable costs of Northwest coal plants showing a weighted average variable cost of approximately 13.0 mills per kilowatthour for the test year. The Spill rate represents a reduction from the Standard rate to reflect changes in marketing conditions.

(3) Displacement Rate

The proposed Displacement rate would be added to the NF-83 rate schedule to be effective when an excess of energy exists on the FCRPS above available markets at the Spill rate. The inclusion of the Displacement rate in conjunction with the Spill rate would help to ensure that BPA displaces the greatest possible amount of thermal generation and would allow an increase in NF-83 revenue. This rate would be similar in concept to the Energy Broker rate. In fact, customers who are participants in the Western Systems Coordinating Council (WSCC) Energy Broker System would not purchase energy under the Displacement rate but would instead use the Broker System and the EB-83 rate.

(4) Incremental Rate

The proposed NF-83 Incremental rate would be applied to sales of power produced or purchased concurrently with the nonfirm sale which BPA may, at its option, not produce or purchase and when the incremental cost is greater than 18.8 mills (the proposed Standard rate less 2.0 mills). The rate would be equal to the incremental cost of the power plus 2.0 mills per kilowatthour.

Issue: The principal issue is whether the Nonfirm Energy rate recovers an adequate level of revenues while displacing thermal resources.

Alternatives: There are alternative ways to structure the rates. It is alleged that the Spill rate has encouraged customers to delay their energy purchases until BPA is in a spill condition. Therefore, one alternative is to eliminate the Spill rate thereby eliminating the incentive for buyers to avoid purchasing at the Standard rate. This alternative is seen as likely to increase revenue from NF-83 sales. In addition, surplus firm power would become more marketable because of the

increase in the price of nonfirm energy. Opponents of this alternative claim that BPA's revenues would decline as BPA would have priced itself out of the market.

BPA has analyzed the effects of eliminating the Spill rate. This analysis indicates that elimination of the Spill rate would increase the revenues BPA would collect compared to the revenues from the NF-83 in the initial proposal. BPA also demonstrated that while potential competition could reduce the expected benefits of eliminating the Spill rate, there was no information available that would indicate that there were substantial quantities of power available to California at rates less than the NF-83 Standard rate but greater than the NF-83 Spill rate. Furthermore, the analysis indicated that surplus firm power would become more marketable because of the increase in the price of nonfirm power.

The analysis on eliminating the Spill rate was based on the Nonfirm Revenue Analysis Program (NFRAP) which forecasts nonfirm energy revenues based on an analysis of 40 water years. The NFRAP modeled Pacific Northwest competition under alternative assumptions. The first assumption is "proportional spill" which models the effect of BPA and Pacific Northwest utilities spilling in proportion with each utilities' total amount of nonfirm energy compared to the total amount of nonfirm energy in the Pacific Northwest region. NFRAP demonstrated that BPA would collect approximately \$63 million more than the NF-83 proposal of a 13.0 mills/kWh Spill rate. The second assumption under which NFRAP was run was that all available non-Federal power is marketed before BPA enters the market. That is, all Pacific Northwest utilities sell all their available nonfirm energy on the intertie before BPA is allowed to sell its nonfirm energy. This assumption is the most conservative assumption possible concerning competition from other Pacific Northwest utilities. Even under this very conservative assumption, BPA still received approximately \$33 million more revenue eliminating the Spill Rate than with a 13.0 mills/kWh Spill rate.

Some aspects of the nonfirm energy market are difficult to model adequately. These factors that would affect nonfirm energy revenues are Northern California hydro generation, minimum generation constraints, Intertie loopflow, and California nuclear plants forecast to come on-line during the rate period. BPA has modeled the nonfirm market using the best information available at this time. Adjustments are made to reduce the California market to account for loop flow, maintenance, firm contracts, and export of non-Federal firm surplus. The NFRAP also assumes that B.C. Hydro has 1500 megawatts available for sale in September and October and 1000 megawatts in November, December, and January. The factors cited above are primarily structural determinants of the nonfirm energy market. That is, BPA could experience a reduction in sales because of the factors regardless of the NF-83 rate level or design.

Competition from suppliers outside the region, either B.C. Hydro or alternate suppliers whose power would not flow over the Intertie, would reduce nonfirm revenues. As stated above, sales by B.C. Hydro have been accounted for in the NFRAP. BPA performed a sensitivity analysis of the effects of different levels of competition on nonfirm energy revenues. The Intertie capacity was reduced by increments of 200 megawatts assuming a scenario of proportional spill and one in which BPA absorbs all the spill.

The Intertie reduction represents increasing levels of competition which would, for example, account for sales to California by B.C. Hydro which are in addition to sales assumed in the base case, or from any source outside the Pacific Northwest region including northern California hydro generation. Under the proportional spill scenario, competition could displace more than 1000 megawatts of BPA nonfirm sales on the Intertie before BPA revenues would be lowered by eliminating the Spill rate. In the most conservative scenario in which BPA absorbs all the regional spill, competition could displace over 400 megawatts before BPA would be worse off by eliminating the Spill rate. Furthermore, little evidence has been presented that substantial amounts of power are available to the Pacific Southwest from other regions at rates less than BPA's proposed rates.

An alternative to eliminating the Spill rate is to delay implementation of the Spill rate. As a spill condition approaches, rather than losing revenues by immediately implementing the below-cost Spill rate, BPA could use the Displacement rate to displace resources with decremental costs too low to displace with the Standard rate, much as it was discussed in the elimination of Spill rate scenarios. Only when it appears that moving to the Spill rate will result in greater BPA revenues or more thermal displacement is such a move prudent. This approach has much of the revenue advantages of the elimination of the Spill rate alternative without the inherent risks.

Another nonfirm energy rate structure alternative is to increase the guaranteed delivery under the Standard rate from 1 day to a multiple day guarantee. California parties assert that a guarantee of a 3-day delivery, for example, would increase both the value and the utility of the energy. However, because of the nature of nonfirm as the "last available" power from the system and its associated unpredictability in the FCRPS, extending the guarantee beyond 1 day would be operationally difficult. For example, if BPA were to schedule delivery of nonfirm for two additional days, BPA would be scheduling nonfirm energy before it knew the amounts of firm power that might be taken under firm contracts.

p. Summary

Table IV-21 presents a summary of rate design adjustments and charges. The purpose of each rate design element is summarized and the affected rates are specified.

TABLE IV-21
SUMMARY OF RATE DESIGN ADJUSTMENTS AND CHARGES

<u>Adjustment or Charge</u>	<u>Purpose</u>	<u>Affected Rates</u>
1. <u>Excess Revenue Credits</u>	Allocates excess revenues derived from NF, DSI top quartile & capacity/energy exchange sales	PF, IP, IH, CF, CE, NR NR, SP, SE
2. Fixed Contract Revenue Deficiency Adjustments	Allocates revenue deficiencies resulting from fixed Canadian Treaty, and Capacity/Energy Exchange Contracts	PF, CF, CE
3. Value of Reserves	Defines reserves and allocates revenue deficiency	PF, IP, IH, CF, CE, NR, SP, SE, NF
4. Surplus Firm Power Revenue Deficiency	Allocates unrecovered costs	PF, IP, IH, CF CE, NR, SP, SE
5. Equalization of Demand	Tradition; Regional Act	PF, IP, CF, CE NR, SP, SE
6. Hanna Adjustment	Allocates revenue deficiency	PF, IP, CF, CE, NR, SP, SE
7. DSI Customer Charge	Revenue stability	IP
8. Billing Determinants for Computed Requirements Customers	Revenue stability	PF, NR
9. Exchange Adjustment Clause	Rebate or surcharge if actual cost differs from that forecast	PF, IP, CF, NR, SP
10. Supply System Adjustment Clause	Adjusts rates if actual cost differs from forecast	PF, CF
11. Low Density Discount	Applies discount to eligible customers to offset high distribution costs	PF
12. Value of Reserves Credit	Applies credit to rate in return for rights to restrict service.	IP, IH
13. Sustained Peaking Surcharge	Additional charge	CF

Table IV-22 presents a comparison of the proposed COSA costs assigned to major rates and the proposed costs after adjustment by the Wholesale Power Rate Design Study (WPRDS) and before equalization of demand as discussed earlier in this section. The adjustments at the WPRDS stage result in higher costs to Industrial Firm Power (IP) customers, primarily due to the addition of unrecovered surplus firm power costs and adjustments for service to the top quartile of the DSI load. The addition of these and other costs overrides the amount of credits associated with the value of reserves and excess revenues, resulting in higher costs allocated to this class relative to costs at the COSA stage. The WPRDS adjustments, primarily the value of reserves cost adjustment, collectively result in a net increase to costs allocated to the New Resource Firm (NR) class.

The WPRDS adjustments result in decreases in cost allocation to the Priority Firm (PF), Firm Capacity (FM), and Surplus Firm Power (SP) classes relative to allocated costs at the COSA stage. The excess revenues credit to these classes is the primary reason for reductions in allocated costs, overriding other adjustments (e.g., Hanna adjustment, revenue deficiency) which increase cost allocations to these classes.

TABLE IV-22

Comparison of Assigned Costs
Proposed COSA and Proposed WPRDS

<u>Rate Schedule</u>	<u>COSA Costs</u> (million \$)	<u>WPRDS Costs</u> (million \$)	<u>Change In Total Costs</u> (percent)
PF	1,874.0	1,761.2	(7.6)
IP	456.8	502.9	10.1
CF	67.5	53.1	(21.3)
NR	10.3	10.4	1.8
SP	190.2	189.8	(.5)
NF	5.4	5.4	0
Total Adjusted Rates ^{1/}	<u>2604.8</u>	<u>2522.8</u>	<u>(3.1)</u>

^{1/} Total costs are different between COSA and WPRDS because of WPRDS adjustments affecting distribution of costs between adjusted rates and other rates (e.g., capacity/energy exchange, CSPE).

3. Rate Structure Alternatives

BPA follows closely its statutory requirements in carrying out its role as a Federal power marketing agency and meeting its total repayment obligations. Both the Regional Act and the Public Utility Regulatory Policies Act of 1978 (PURPA) serve as guidelines for BPA's rate design process. While the former Act has been described in some detail, the latter bears some description at this point. PURPA provides several guidelines for utilities. It sought to encourage (1) conservation of energy supplied by electric utilities; (2) optimization of the efficiency of use of facilities and

resources by electric utilities; and (3) equitable rates to electric consumers. To work towards accomplishing these objectives, PURPA set forth ratemaking standards (section III(d)(1-6)) for consideration. These standards include (1) cost of service; (2) declining block rates; (3) time-of-day rates; and (4) seasonal rates. The cost of service standard (Public Utility Regulatory Policies Act of 1978 (PURPA), 1978, Public Law 95-617 - Nov. 9, 1978, 92 STAT. 3117 - 3173; section III(d)(1)) applies to all rate designs and states that "Rates charged by any electric utility for providing service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class"

The sections which follow address (1) flat rates; (2) declining block rates; and (3) tiered 7(b) rate.

a. Flat Rates

BPA's proposed rates (PF-83, IP-83, CF-83, CE-83, NR-83, SP-83, SE-83, NF-83, RP-83, IH-83) are flat and not variable rates, some of which are differentiated diurnally and seasonally.

Under a flat rate, a constant price is charged for each unit of electricity consumed. Flat rates usually are based on average system costs. If BPA were to establish a flat rate set at its marginal cost, a sizeable amount of excess revenue would be produced. Approximately one-third of the large private utilities and approximately one-half of the public utilities in the Northwest in mid-1982 had average cost based flat rates for their residential customers.

Flat rates meet the objectives of being easy to understand and to administer. If these are set to recover the revenue requirement, revenue stability problems are relatively limited. However, when based on average system cost, and assuming that marginal costs differ from average cost, flat rates give distorted signals to consumers because the cost of additional electricity does not reflect the true cost of meeting that incremental load with new resources. Consequently, consumers are not encouraged to make efficient consumption choices because incremental resource costs are masked in averaging the cost of older low-cost resources with new high-cost resources (Watson, et al., 1981, p. 33). These inefficient consumption decisions could encourage construction of unwarranted generation and result in negative physical environmental effects from facility construction and operation. As a result of the poor consumption decisions caused by distorted price signals, there could be long run negative socioeconomic effects as well.

b. Declining Block Rates

BPA has not used declining block rates. A declining block rate design applies to successive blocks of electricity at progressively lower per unit prices. Traditionally, declining block rates have been used to reflect decreasing costs per unit of production. When electric utilities were growing, declining block rates were justified by economies of scale and technological improvements and were used to promote revenue stability. Declining block rates signaled customers to use increasing amounts of

electricity because per unit costs were declining. Approximately one-third of the public utility systems in the region currently have declining block residential rates.

The cost conditions of an earlier period no longer exist. The PURPA standard on declining block rates (PURPA, Section III(d)(2)) states that "The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatthour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period."

As consumption increases, BPA's system costs do not decrease. BPA has largely exhausted the potential development of additional low-cost hydro resources. Incremental additions to generating capability are derived from high-cost thermal plants. When expensive thermal generation is added to meet load growth, it is argued that the declining block rate becomes an inefficient design, because it encourages consumers to increase their consumption (Watson, 1981, p. 32). Furthermore, negative physical impacts associated with facility construction and operation occur.

c. Tiered 7(b) Rates

The issue of a tiered rate structure has been raised in each of the past three BPA wholesale rate filings. BPA rejected the use of a tiered rate structure in each of these filings based on both conceptual and implementation problems.

As stated in the 1982 Administrator's Record of Decision (BPA, 1982a), BPA is concerned about the potential adverse effect of a tiered rate structure on BPA's revenue stability. A large portion of BPA's costs are fixed and do not vary as load varies. Also, a tiered priority firm rate may introduce inequities into the sale of priority firm power and could create serious cash flow problems for customers. The staff of the Regional Council has recognized that the equity problems are severe and that there is no consensus as to how tiered rates may be implemented because of the heterogeneity of BPA's customers. In addition, in light of BPA's responsibility to provide billing credits for conservation and consumer owned renewable resources, as required by the Regional Act, a tiered rate imposed for the purpose of discouraging consumption of electricity may be redundant and therefore unwarranted. Finally, tiering the Priority Firm rate would significantly increase BPA's administrative responsibilities. For instance, there are certain difficulties inherent in billing, data collection, in making appropriate calculations, in determining with relative certainty whether the desired objective would be met, and in reaching a prescribed revenue level.

Revenue Stability: Tiered rates adversely affect revenue stability because the structure of the rate creates a greater reliance on sales subject to the upper tier for meeting the revenue requirement. Thus,

any failure to realize anticipated load can potentially lead to a greater revenue shortfall. Numerous factors, including weather, economic conditions, and conservation programs could produce such a result.

BPA's ability to withstand large swings in revenue has declined significantly in recent years. The only expenses which BPA can currently defer are interest and O&M financed through Congressional appropriations. As summarized in Table IV-23, deferrable costs as a percentage of total costs have declined from 81 percent in 1975 to a projected 11.8 percent in 1983.

TABLE IV-23
DEFERRABLE COSTS AS PERCENT OF TOTAL COSTS
FY 1975--FY1983

Fiscal Year	Percent
1975	81.4
1976	62.1
1977 a/	54.9
1978	47.2
1979	45.0
1980	40.3
1981	32.0
1982	16.3
1983	11.8

a/ Includes the Transition Quarter

Source: BPA, 1982b.

The results of this analysis must be viewed in light of BPA's commitment to fiscal integrity.

BPA's ability to lower costs is also severely limited in the short run. New obligations and programs which BPA could decide not to undertake include additional resource acquisitions, new conservation programs, and non-contractual fish program commitments. In the 1983 budget 2.24 percent of total expenses collected through BPA rates were discretionary, in the 1984 preliminary budget, 3.14 percent are discretionary, and in 1985, 3.42 percent. Since BPA's flexibility to deal with revenue shortfall is limited, both in terms of reducing costs and deferring payments, BPA has concluded adoption of a tiered rate design would be imprudent at this time.

When considering the potential revenue shortfall under a tiered rate structure, mitigating factors must also be considered. One such factor is the fact that if tiered rates actually caused a reduction in firm load, there would be the potential for increasing sales under the nonfirm energy rate. These sales can lessen the impact of the potential revenue shortfall caused by a reduction in firm load. However, a nonfirm sale priced at the current nonfirm energy standard rate of 18.2 mills per

kilowatthour would not fully mitigate the revenue loss of a priority firm sale priced at the margin. Based on existing rates, if the top tier reflected BPA's long run incremental cost-based energy rate of 42.21 mills per kilowatthour, the revenue loss would be 24.01 mills per kilowatthour due to a reduction in priority firm load even considering the mitigating effect of a nonfirm sale. If the nonfirm sale were made at the spill rate of 9.0 mills per kilowatthour, the revenue loss would be much greater. Thus, the potential loss of revenue would be much greater under a marginal priced tiered rate structure than under a melded rate structure. Furthermore, at this time BPA and the region are faced with a surplus condition which increases the likelihood that surplus power would be spilled or marketed at the spill rate.

Tiered rates would also combine poorly with BPA's energy conservation program, because they would exacerbate the lost revenue effect. The effect of BPA-funded conservation on other customer's rates includes lost revenue from energy conserved. Thus, if BPA funded a conservation program for a utility consuming upper tier power costing 50 mills per kilowatthour, the lost revenue effect on BPA's rates would be greater than if the unrealized sale due to conservation had been priced at BPA's melded rate.

Finally, tiered rates are of questionable value during a period of surplus, because they would send an inflated price signal concerning short run value to the region of reductions in usage. Tiered rates also would not differentiate between reductions in usage due to improvements in efficiency and reductions due to curtailments and fuel switching. BPA believes that the conservation and billing credit programs, which provide a focus on long term improvements in efficiency rather than short term curtailments, are more appropriate during the surplus period than tiered rates. These are the mechanisms which Congress included in the Regional Act, and they should be given an opportunity to work.

Exchange Mechanism: Another reason why BPA has not designed a tiered rate for 7(b) customers is that such a rate would interfere with the residential exchange mechanism stipulated in the Regional Act. The purpose of the exchange is to extend the benefits of the Federal base system resources to residential consumers of private as well as public utilities throughout the region. All approaches to tiered rates could interfere with this concept. For example, if the 7(b) rate were tiered, the average cost of priority firm power to the private and public utilities could differ significantly. Since public bodies and cooperatives have historically tended to have higher usage per customer, a greater proportion of their loads would be subject to the top tier charge as compared with private utilities.

An approach to tiering based on some measure of historical consumption could be perceived as discriminating against the private utilities. Because of their lower usage per customer and long standing conservation programs, the private utilities probably have less potential for the usage reductions that this rate structure would reward.

Proposed Tier Size: There are several ways of arriving at the size of rate tiers. One is to establish the size of the lower tier

as some function of usage per customer and usage per employee. "Customer" is intended here to mean the ultimate residential consumer and "employee" means an employee of a commercial or industrial establishment in a utility's service district. Using a method based on some function of number of residential consumers and employees is easily understood and addresses many of the equity problems associated with tiering based on historical usage because utility areas experiencing rapid growth would not be adversely affected and past conservation measures would be recognized.

Although BPA recognizes some specific merits of this method, some of the associated problems deserve consideration. First, any method in which the tiering is not based on recent historical or forecasted consumption has the problem that some utilities probably will not face the top tier. Thus, the benefit of the improved price signal to some utilities may be offset by the below average cost signal to other utilities. Also, this method could discriminate against utilities serving energy intensive industries. Implementing this approach also poses special informational problems. The data required may be difficult to obtain and verify, and subject to economic swings. Using a per employee function makes the price signal subject to economic conditions.

Another implementation difficulty is determining the amount of consumption. Presumably, the size of the lower tier should be based on number of residential consumers sized to meet basic residential needs. Determination of the basic needs of residential consumers is a function of such factors as climate, family size, use of electricity for space or water heating, etc. Determination of the basic needs per employee is also a function of such factors as weather, type of work performed, level of production, etc. To the extent that the basic needs calculation does not take these into account, it could be perceived as being inequitable. The number of adjustments necessary to approach equity would entail considerable burden, and could prove to be administratively impractical and unworkable.

Pricing of the Top Tier: One of the goals often mentioned in connection with tiered rates is that of exposing consumers to marginal costs. Two ways in which BPA could do this would be to price the top tier at the regional long run marginal cost or the regional short run marginal cost.

Regional long run marginal costs would send the correct price signal: the cost to the region to supply an additional increment of load. Assuming BPA will meet all future increments of load, the BPA long run incremental cost (LRIC) would equal the regional long run marginal cost. This being the case, the difference between BPA's average and incremental costs is substantial and pricing at the LRIC could, at least in the short run, be quite economically disruptive to the region. Furthermore, this difference would confine recovery of the bulk of BPA's revenue requirement to a small proportion of sales subject to the upper tier rate. This could significantly destabilize BPA's ability to collect revenue. Revenue instability would also result from the difference between long run and short run incremental costs.

The short run incremental cost at which the top tier could be priced could be based on the revenue BPA would receive from sale of

an additional increment of power or the costs saved by not serving an additional increment of load. This pricing scheme would not be as disruptive as pricing at BPA's LRIC. Theoretically, this method could lead to greater revenue stability than average rates because the upper tier would better track the cost/revenue impact of load changes. However, if it is determined that reductions in load during the surplus period would result only in greater nonfirm sales at the spill rate, this method would result in a declining block rate. Therefore, the failure to reflect long-run costs could result in uneconomical consumption habits and inappropriate evaluation of the cost effectiveness of conservation investment savings.

J. Mitigating Measures

1. Introduction

As previously noted, the no-action, proposed, and LRIC alternatives for both the November 1, 1983, to June 30, 1985, rate period and the cumulative period vary in their effects on consumers. For example, the no-action alternative could create a need for additional generation resources, leading to adverse effects on the physical environment. The LRIC alternative would cause large increases in the price of electricity. While this would adversely affect the socioeconomic environment in the short run, it would also reduce the demand for electricity and decrease the need for new generation with its associated physical environmental effects in the long run.

In FY 1981, BPA started energy conservation programs targeted at primary customer groups, State and local governments, and nonprofit consumers in the Northwest. Space and water heating are the predominant end uses affected by these programs. Conservation programs currently offered by BPA and proposed for the rate period are designed to mitigate BPA's obligation to serve the loads of its customers. Under the Regional Act, BPA is required to treat conservation as the region's highest priority resource and to initiate a set of energy conservation programs. These programs are listed below by consumer group and fiscal year when initiated. Each is then briefly described.

2. Programs for Residential Consumers

The programs offered to residential consumers include energy acquisition and capability development programs. Each of the programs is discussed below.

<u>Programs</u>	<u>Fiscal Year of Start Up</u>
I. Residential Consumers	
A. Weatherization	1982
B. Solar and Heat Pump Water Heating Pilot Program	1983
C. Solar Domestic Water Heating Program and Solar Water Heating Workshop	1983
D. Appliance Efficiency	1983
E. New Home Construction	1983
II. Commercial Programs	
A. Energy Audit	1983
B. Financial Incentives	1984
C. Pilot Programs	1983
III. Industrial Programs	
A. Sponsor-Designed Conservation	1983
B. Industrial Audit	1983
IV. Public Agencies and Customers	
A. Street and Area Lighting	1982
B. Institutional Buildings	1983
C. Assistance for State/Local Governments	1983
D. Customer System Efficiency Pilot Program	1983
V. Program Development	
A. Marketing and Evaluation	1983
B. Technical Studies	1982

a. Residential Weatherization

More than half of the FY 1982 residential funds supported residential weatherization activities. This trend will continue because residential weatherization is one of the most cost-effective and widely supported energy conservation programs. BPA's residential weatherization program, including a sub-program to assist low-income consumers, will help consumers offset higher electricity rates. A variety of measures are offered under the weatherization program: ceiling and attic insulation and ventilation, floor insulation, insulation of unfinished walls, windows, weatherstripping, caulking, duct insulation, clock thermostats, and water heater and pipe insulation. The program retrofits existing electrically heated housing stock.

The residential weatherization program is offered to BPA's public and private utility customers who may deliver weatherization measures to their consumers through either zero interest loan or buy back financing mechanisms. Under the former option, no interest, deferred repayment loans are offered to consumers based on actual weatherization retrofit costs determined by competitive bidding; capital outlays by utilities for weatherization retrofitting are not required. Under the buy-back option, BPA reimburses utilities at a fixed rate per kilowatthour for expected energy

savings resulting from measures installed in residences. The residential weatherization program is currently targeted as a 10-year effort and will be coordinated with related programs in place or proposed.

BPA is making a special effort to encourage weatherization by low-income households. Money is channeled through utilities, states, or community action agencies to administer home conservation measures. As in all programs, the objective is to reduce the electrical load that must be served by the BPA Administrator.

BPA is also attempting to evaluate the cost-effectiveness of maximum weatherization. In conjunction with Pacific Power and Light and Hood River Electric Cooperative, BPA has launched a "maximum energy savings" pilot weatherization program in Hood River. Program costs and energy savings will be evaluated to determine if such an approach is applicable elsewhere in the region.

b. Solar Heat Pump Water Heater Pilot Program

This pilot program is designed to test marketing approaches and to establish appropriate incentive levels for the application of commercially available heat pump water heaters and solar water heaters. The solar/heat pump water heater program will be offered to several of BPA's utility customers who will install devices in single- and multi-family households that use electric water heating. Reimbursement for costs will be through a buy-back mechanism similar to that employed in BPA's residential weatherization program.

c. Solar Domestic Water Heating Program and Solar Water Heating Workshops

These two solar programs provide information, along with potential payments, to homeowners with electric water heaters who install solar water heaters. The programs have been in effect since 1981 and will be discontinued during 1984.

d. Appliance Efficiency

The appliance efficiency program provides information to consumers on the relative energy efficiency of various brands of home appliances. With this information, potential purchasers are able to select energy-efficient appliances. Information to encourage current appliance users to use their appliances in the most energy-efficient manner also is provided. Expected program life is 15 years and frequent updating of appliance information is planned. Testing of financial incentives for purchasers, retailers, and distributors of the most energy-efficient items is also planned. The total program is seen as a long-term effort with benefits offering potential savings accruing in a time of regional energy deficit.

e. New Home Construction

This program offers incentive payments to encourage either conservation or solar design techniques in the construction of electrically heated homes. Consistent with Regional Council standards, utilities establish

program details to address local conditions. The objectives of the pilot program are to reduce the BPA load requirements from new homes by encouraging homes to be constructed to meet higher efficiency standards.

3. Commercial Programs

Approximately 20 percent of the electric energy sold in the Pacific Northwest at the retail level is consumed by the commercial sector. Although there are relatively few existing programs to use as models (as contrasted with the residential sector), BPA's current resource surplus is providing the opportunity to test proper options in this sector. BPA's program for commercial customers focuses chiefly on cost-effective measures that demonstrate the greatest potential for electric energy savings and provide a framework for future conservation activities. Three subprograms that constitute this commercial sector program are discussed below.

a. Energy Audit

The energy audit program will be delivered through regional entities (i.e., utilities, architectural and engineering firms, et. al.) to their commercial consumers. BPA reimburses program operators for conducting commercial energy audits to identify conservation costs and energy savings. There are three audit levels: Level I, which identifies low-cost and no-cost operation and maintenance conservation measures and lighting and domestic water heating conservation measures; Level II, which includes Level I analysis and a simplified energy analysis that identifies simple retrofit conservation measures; and Level III, which includes a detailed computer simulation that identifies conservation measures for complex buildings. The choice of the appropriate level of audit depends on the complexity of the building's energy-use systems and the total annual energy consumption.

b. Financial Incentives

In conjunction with the commercial energy audit, this program provides funds to help commercial consumers finance the installation of energy conservation measures. Cost-effective measures for achieving available energy conservation will be identified through BPA-approved audits. BPA has estimated that 700 average megawatts could be saved in regional load growth if existing buildings were properly operated, maintained, and retrofitted.

c. Pilot Programs

Several new commercial customer pilot programs have been designed, including a new commercial buildings pilot project, workshops on commercial conservation products and techniques, and irrigated agriculture expanded pilot project activities. Each is described in turn.

The new commercial buildings pilot project will be based on studies of innovative approaches to stimulate increased energy efficiency in new commercial buildings. Technical assistance will be offered through workshops on commercial conservation products and techniques.

Since the early 1950s, utilities, universities and others have conducted research on irrigation efficiency improvements. BPA's pump testing pilot program, which ran from 1979-1981, is one example. But until now, little hard data was available on the energy savings available from irrigation efficiency improvements -- which ones were cost effective and which were not, and how to package them into a program. There was no comprehensive utility program of on-farm analysis and incentives for cost effective improvements which BPA could use as a model in designing its own program.

Phase I of BPA's program began in 1982, with the purpose of collecting data from on-farm analysis which would identify which measures were cost effective and help iron out some of the administrative details in preparation for offering incentives. By September, trained inspectors from 10 participating utilities had completed about 150 analyses in this information gathering phase. In 1983, 26 utilities are participating in Phase I.

Phase II of the irrigated agriculture pilot program, available to the 1982 Phase I participants, began this year. BPA has budgeted about \$500,000 for this year's financial incentives offered to farmers in this phase of the program. In addition to providing incentives, the program trains farmers in optimum irrigation practices, emphasizing how to combine energy efficiency with stress-free crop growth. Local weather data, gathered by weather stations established by BPA and relayed by satellite to a Bureau of Reclamation computer, are used to calculate the optimal time and amount farmers should irrigate. It is an intensive program which requires substantial commitment from the utility and the farmer. Three utilities are participating in the program this year.

4. Industrial Programs

BPA's industrial programs will address conservation potential in the industrial sector through (1) industrial audits and (2) sponsor-designed conservation. Each is discussed separately.

a. Industrial Audit

The industrial audit will be developed in test, pilot, and regional phases. Currently, we intend to test the effectiveness of two levels of audits in stimulating energy efficiency. Audits will recommend low-cost adjustments in operations and maintenance, motor efficiency improvements, and other energy-saving measures. This program will be aimed at non-DSI's and industries using all electrical equipment.

b. Sponsor-Designed Conservation

The sponsor-designed conservation program encourages development of and facilitates BPA acquisition of site-specific and subregional conservation and direct-application renewable resources (DARR). Funding is also provided for feasibility studies to gather the information necessary to determine the viability of a particular conservation program or project.

BPA recognizes that conservation and DARR efforts planned and designed by others are an important ingredient in capturing the potential

conservation available to the region. Utilities, as well as other potential program sponsors, have expressed a desire to design their own efforts independent of BPA. In addition, there are specific projects or programs that are unique and do not lend themselves to regionwide application.

During this period of resource surplus, this program will focus on building capability to acquire energy savings through sponsor-designed efforts. In building that capability, the objectives of the program are:

- To test the procedure, evaluation criteria, and administrative and oversight capabilities necessary for the program's success.
- To test the capabilities of different types and sizes of entities available to deliver energy savings to BPA.
- To build an inventory of programs and projects which can be brought on-line quickly to enhance the flexibility of the regional resource picture.

As the anticipated resource deficit approaches, acquisition of sponsor-designed efforts will increase to help meet energy needs.

While BPA has the responsibility to accept conservation or direct-application renewable resources proposals, these will be measured against the near-term resource acquisitions policy. As stipulated by the Regional Act, such acquisitions must meet cost-effectiveness criteria, including environmental costs, and meet fish and wildlife criteria. The resource mix analysis currently identifies conservation under 35 mills per kilowatthour as cost effective for FY 1984. In estimating energy savings, a cost of 30 mills per kilowatthour is assumed.

5. Public Agencies and Customers

Four subprograms constitute the energy conservation activities offered by BPA to public agencies, state and local governments, and nonprofit organizations: street and area lighting; institutional buildings; assistance for state and local governments; and a customer system efficiency pilot program.

a. Street and Area Lighting

Most street lighting is used to illuminate arterial and residential streets. Many existing street and area lighting systems use mercury vapor or less efficient fixtures such as incandescent lamps. The BPA street and area lighting program to be implemented through utilities is designed to encourage conversion to more energy-efficient systems (e.g., high pressure sodium vapor) throughout the region. Potentially, the street and area lighting program could reduce, by 37 percent, the amount of energy that otherwise would be used in the region for street lighting purposes. BPA would pay utilities a set reimbursement for both labor and capital costs associated with fixture conversion.

b. Institutional Buildings

This program is designed to acquire electricity savings through the installation of energy conservation measures in institutional buildings, such as schools, hospitals, public care institutions, and most public buildings. The program operates through each state government in the region under a conservation purchase contract. This three-step program includes a walk-through energy audit, technical assistance study, and implementation of cost-effective electricity saving measures identified in the technical assistance study. Cost-effective electricity savings measures include weatherization, lighting, water heating, and motor and pump efficiency improvements. This program funds energy auditor training, technical assistance studies, installed electricity saving measures, and the states' administrative costs associated with implementing the program. The program is modeled after the Department of Energy's Institutional Buildings Grant Program established in 1979.

c. Assistance for State Local Governments

Using the services of the State government energy offices, BPA will provide technical assistance to local governments. Cooperative agreements serve to assess energy savings potential among local energy resources and to encourage the development of small scale generation from renewable resources. Improving facilities management by local government and developing appropriate energy efficient codes and zoning ordinances are two other subprograms. These seek to strengthen the local role of enforcement of minimal thermal and lighting efficiency standards set forth in State codes. Regional energy savings could be increased noticeably through stronger codes and ongoing enforcement activities.

Additional technical assistance and technology transfer activities carried out through the State energy offices will include information and referral services, resource libraries, workshops, and classes. Topics will include efficiencies in space heating, water heating, and lighting as well as solar and other renewable resource applications. Funds for programs implemented through units of local government and Indian tribes will be available to support energy conservation and renewable resource development planning.

d. Customer System Efficiency Pilot Program

The first phase of this program assesses the cost effectiveness of improving system efficiency. This pilot program funds partial costs of measures taken by BPA's utility customers to reduce electricity losses in their transmission and distribution systems. Strategies include reconductoring distribution lines, replacing transformers, sizing new facilities, and increasing voltage levels. As a follow-up, another pilot program will operate from 1984 to 1986. On a cost sharing basis, BPA will help five utility systems reduce system losses.

To date, BPA has promoted the development and use of a guidebook to assist utility customers in analyzing systems and in determining the potential of cost effective measures to conserve energy.

6. Program Development

Marketing and technical studies provide support to program development and improve the effectiveness of conservation activities in the Pacific Northwest.

a. Marketing and Evaluation

This program activity includes investigation and testing of potential external financing techniques, evaluation of the effectiveness of conservation programs, and assessments of the conservation potential available in the region.

External financing investigations cover a broad range of potential sources of financing for conservation to supplement BPA's borrowing authority. The range of BPA's efforts reflects the need to design financing mechanisms to meet the specific needs of each of the economic sectors affected.

Under a "shared savings" approach, third party installers of conservation measures and private sector financiers would be reimbursed by BPA or by the end use electricity user based on the value of energy saved. Installers would profit because of the difference between the cost of achieving the energy savings and the value to BPA of reducing the need for additional generating resources. Investigations are also underway focusing on leasing mechanisms in the industrial sector as a means to finance conservation. Work is continuing on developing a mechanism to use publicly owned utility tax exempt revenue bonds to finance conservation, with BPA arranging to assume debt service obligations on the bonds. Under a joint project with the Department of Energy, BPA is analyzing the potential for private financing alternatives for implementation of conservation measures in the public and private nonprofit sectors. BPA is also developing an information exchange program for use with primary lenders to encourage financial institutions in the Northwest to use innovative financing mechanisms developed elsewhere to implement conservation.

Program evaluation activities cover residential, commercial, industrial, and nonprofit institutional conservation programs. These activities seek to ensure that BPA's conservation efforts are effective and economical.

In assessing conservation potential, BPA addresses the broad potential for cost effective conservation in the region as well as conducts detailed investigations into the factors affecting implementation of conservation measures by consumers. Investigations also are conducted into the effect of conservation measures on system peakloads and on the potential for displacing the need for additional transmission capacity through implementation of conservation. A major case study of marketing techniques initiated in FY 1983 may be continued in FY 1984, providing the region with a test of the effectiveness of mass marketing techniques in stimulating conservation in the residential sector.

b. Technical Studies

A set of technical studies will be pursued to support program development and to improve the effectiveness of current BPA conservation and renewable resource programs and projects. Covering a 5-year period, this program encompasses all phases of conservation and improved energy efficiency activities including example studies listed below:

- . solar radiation data analysis
- . solar assessment by aerial survey
- . sizing solar collectors from system test results
- . marketing strategies to meet conservation objectives
- . unsolicited technical studies
- . residential photovoltaic study
- . residential passive solar retrofit study
- . indoor air quality/radon research
- . solar audit methodological development
- . water heater piping retrofit
- . solar batch water heater performance study
- . wall insulation retrofit
- . movable window insulation
- . C-Factor Analysis
- . energy efficient appliance rating system
- . residential energy efficiency rating system development

These projects will build on current data bases and findings from earlier BPA and DOE studies. These studies also document the effectiveness and environmental impact of conservation measures prior to inclusion of the measures in BPA conservation programs.

7. Billing Credits

Another measure that may mitigate the financial impact of increased electricity rates is BPA's billing credit program. Mandated by the Regional Act, billing credits are payments from BPA to eligible customers for actions by those utility customers which reduce their power needs and thereby reduce BPA's obligation to acquire additional generation resources. An eligible customer is considered one who has signed a power sales contract with BPA pursuant to provisions of the Regional Act, taken BPA load reduction actions after December 5, 1980, and has requested a billing credit. Payment to the customer may be in the form of either an offset to the customer's power bill or a cash payment if the amount of the credit exceeds the amount of the power bill.

Actions that reduce BPA's responsibility to acquire resources and which are eligible for billing credits include the following:

- . conservation measures independently undertaken, i.e., carried out independently of actions funded or offered by BPA or included in the plan of the Regional Council, by customers or political subdivisions served by customers

that (1) reduce electric power consumption and, (2) occur as a result of an increase in the efficiency of energy use, production, or distribution;

- resources constructed, completed or acquired by a customer, or a political subdivision served by the customer, including actual or planned load reduction resulting from direct application of a renewable energy resource or from a conservation measure;
- retail rate structures voluntarily implemented by customers which induce conservation or installation of consumer owned renewable resources.

Billing credits are substitutes for the acquisition of resources by BPA through independent customer activities. To the extent that higher costs, i.e., higher rates by BPA associated with new generation resources, are reduced or avoided by participation in the billing credit program, and to the extent that these lower costs are passed through to the consumer by BPA customers, consumers will be given assistance to help mitigate impacts of electricity rate increases.

8. Income Support

Government income support programs exist which can assist residential low-income and elderly poor consumers in reducing the severity of impact of any BPA rate increase. One such program for eligible applicants (at or below 125 percent of poverty level guidelines) is the Federal Low-Income Energy Assistance Program (LIEAP). LIEAP programs and programs for the aged are administered by states in the region in conjunction with Community Action and area senior service agencies. There are typically two methods by which low-income households receive support: (1) a one time annual cash payment made to the home energy supplier, e.g., a utility, on behalf of the applicant, or (2) a one time annual cash payment made directly to the applicant in those cases when the applicant is a renter or indirect energy consumer, or when the home energy supplier does not participate in the program. The size of LIEAP payments usually depends on geographic location and the type of fuel used as the primary heating source, as well as income. For example, an Oregon nonfarm family of four with an income range of \$5,000 - \$7,500, a primary heat source of electricity and residence west of the Cascades would receive a payment of \$130 in 1982 (Oregon Department of Human Resources, 1981). Eligible low-income households are asked to have energy audits of their dwellings and to participate in available weatherization programs to encourage energy conservation.

9. Other Mitigating Measures

Through design of its rates and development of new marketing policies, BPA has taken a number of steps to help hold down power costs for industrial and irrigation power consumers. BPA has proposed several changes in the seasonal differentiation of its rates that will benefit irrigated agriculture. In BPA's existing rates, the summer pricing period for capacity is June through November. BPA is proposing for its 1983 rate proposal that May be included in the summer capacity season. Pricing capacity purchased in

May at the lower summer capacity rate will benefit irrigators because May is an important irrigation month. BPA's proposed 1983 rates also reflect an increase in the energy pricing differential between the winter (September through March) and summer (April through August) pricing periods. This shift of more costs from the summer to the winter periods would also benefit irrigators who purchase power primarily during the summer period. Both of these measures would encourage continued irrigation operations and possibly continued growth of irrigated agriculture.

To help alleviate some of the effects of higher power costs on the DSI's, BPA is offering the DSI's a limited contract for low-cost surplus power. The surplus power, much of which might otherwise be spilled over the Columbia River dams or sold for lower prices, will be available to the DSI's at 11.2 mills per kilowatthour for loads exceeding current operating levels. The power will be available from March 22 to October 31, 1983, the day before the proposed 1983 rates take effect. Because BPA's aluminum company customers are operating at about one-half capacity, this arrangement should result in increased industrial operations and employment and make use of power that might otherwise be wasted or have a very low value. By increasing immediate BPA revenues, these sales might reduce the amount of revenues BPA would otherwise have to recover through rates.

BPA also is attempting to mitigate the impacts of higher electricity rates by allowing retail utilities to purchase lower cost secondary energy to serve certain retail interruptible loads. BPA has offered an interim agreement for nonfirm power, effective through June 30, 1983, to Northwest utilities customers for use in serving specified interruptible industrial or agricultural loads. Several utilities are participating in this agreement. BPA is currently exploring long-term arrangements for selling nonfirm energy to requirements customers for use in serving interruptible loads.

K. Unavoidable Adverse Impacts

The unavoidable adverse impacts resulting from implementation of BPA's rate increases would be primarily socioeconomic in character. Effects on low-income residential consumers are of special concern. An increase in the priority firm rate, under which BPA serves publicly owned utilities and the residential and small farm load of investor owned utilities, would necessitate increases in these utilities' retail electricity rates to consumers. To the extent that BPA's increase is passed on to the consumer in higher retail rates (which depend on each utility's cost and rate structure), consumers in the region will pay more for electricity. This increased cost of electricity would have the greatest effect on low-income consumers because they generally devote a greater proportion of their income to purchases of electricity and have less flexibility in their income to adapt to increased costs than is true for other consumers. To the extent that BPA's power is consumed outside of the region, the proposed rate increase also will have an impact on the consumers outside of the region.

The cumulative effects of the past and proposed BPA rate increases from December 20, 1979, to November 1, 1983, would result in a wholesale rate increase of 495 percent over the 4-year period. Thus, the recent cumulative

socioeconomic impacts on low-income consumers substantially exceed those due to only the proposed increase and expand the serious effects of power rate increases beyond the low-income residential consumer.

The proposed 1983 and cumulative rate increases are not expected to have serious adverse impacts on those industrial users who are profitably operating, because electricity costs are generally a small portion of total costs and can be passed through as higher prices to their customers. Past rate increases have adversely affected marginal irrigators, commercial firms, and highly energy intensive industries, many of which have had difficulty achieving the energy efficiency levels necessary to remain competitive. In many cases, current economic conditions have also precluded passing through electricity costs as higher prices to their customers. The effect of BPA rate increases over the cumulative period may in some cases prove to be a contributing factor in the discontinuation of individual commercial, industrial, or farm operations. In 1983, BPA is proposing only a slight increase in its industrial rates. Therefore, there would not be any significant adverse effects on energy intensive industrial customers. For irrigators, the increase in BPA's Priority Firm Power rate would be somewhat offset by BPA's inclusion of May, an important irrigation month, in the off-peak capacity pricing period.

L. The Relationship Between Short-Term Uses of the Environment and Maintenance and Enhancement of Long-Term Productivity

This section identifies the nature of the tradeoff between various short-term uses of the environment associated with increased electricity rates relative to long-term options they may preclude. As discussed elsewhere in this statement, the short-run effects of BPA's proposed rate alternative would be primarily socioeconomic, resulting in significant financial impact on low-income residential consumers in particular. The LRIC alternative would significantly affect the financial condition of low income residential consumers as well as energy intensive industries and irrigated agriculture. The full effects of BPA's rate alternatives will likely develop gradually over a period of years as consumers adjust to higher prices. For example, the anticipated increase in BPA electricity costs would, over the next 20 years, enhance the cost effectiveness of conservation and stimulate adoption of measures to improve the efficiency of energy uses. It is expected that measures such as capital intensive home and business weatherization, replacement of inefficient energy consuming devices with more efficient ones, and changes in electricity use habits will greatly contribute to the projected declines in electricity consumption under the proposed and LRIC alternatives relative to the no-action alternative (see Chapter II).

Concerns over the effects of long-term electricity generation options for the Northwest are focused primarily on the physical environment (e.g., the rate of consumption of nonrenewable resources such as coal, oil, gas, and uranium). The depletion of nonrenewable resources would be slowed by energy conservation measures adopted by regional consumers in the face of higher electricity costs. It is estimated that the proposed rates would avoid a need which would otherwise exist under the no-action alternative for nameplate capacity equal to 49 megawatts of conservation, 11 megawatts of cogeneration, 416 megawatts of small hydro, and 1,131 megawatts of large thermal generation by the year 2000. Corresponding savings for the LRIC alternative would amount

to 1,034 megawatts of conservation, 393 megawatts of cogeneration, 2,571 megawatts of small hydro, and 1,131 megawatts of large thermal generation by the year 2000. (See Table II-10.)

Coal and nuclear power systems have the primary environmental impact potential in the region. By avoiding the construction and operation of coal or nuclear generation facilities, long-term impacts on land use, the creation of solid waste, and adverse water quality and air quality impacts would be reduced. Additionally, minimizing regional dependence on thermal plants would free scarce capital and manpower resources for other productive uses. To the extent that the effects of coal or uranium mining, processing, and power production cannot be avoided, Federal law requires mitigation of some of these impacts (e.g., regrading and revegetation of mined areas). Other long-term effects associated with coal or uranium mining, such as destruction of underground water aquifers and contamination of ground water, would be very difficult to correct. Furthermore, the long-term options for the required isolation of high level nuclear waste from the environment for extremely long periods of time remain incompletely developed. While the Federal government is currently investigating key nuclear waste management and disposal issues, no permanent, high level waste repositories have been selected to date. The mechanical malfunction of nuclear plants, combined with possible human error, also pose the potential for serious environmental consequences. As in the case of the 1979 nuclear plant accident at Three Mile Island, there is the potential for the release of dangerous amounts of radioactive material into the environment and, in a worst case situation, long-term destruction of life and life support systems.

Other long-term options of the proposed and LRIC rate alternatives entail fuel switching from electricity to wood, natural gas, and, to a decreasing degree, fuel oil. To the extent that switching to a fossil fuels occurs, finite reserves of these resources would be depleted, and could produce associated environmental degradation, especially with regard to local air quality. One counter consideration to this is that lower rates which discourage fuel switching at the consumer level are more likely to result in a future need for thermal generation on BPA's system (e.g., coal, nuclear, cogeneration, and combustion turbines). For impacts association with these technologies, the reader is referred to Section IV.H.

Finally, agricultural productivity would be affected by the LRIC rate alternative, especially in the case of the cumulative analysis.

M. Irreversible or Irretrievable Commitments of Resources

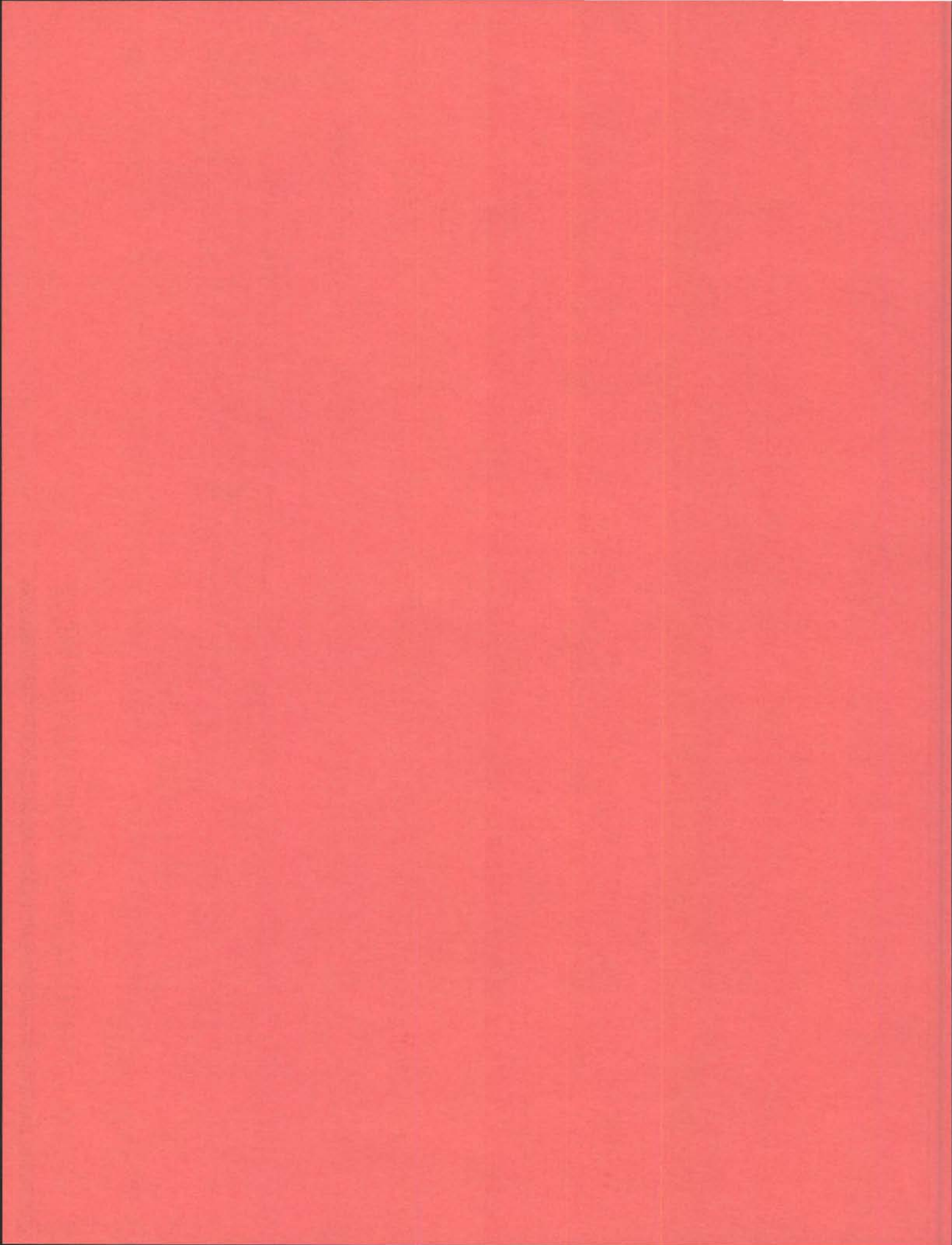
This section identifies natural resources which may be expended as a result of increased electricity rates as described herein. Acceleration in the depletion of natural gas would be the chief resource commitment resulting from a large increase in BPA's wholesale rates.

To the extent that increased electricity prices in the Northwest stimulate greater end use of natural gas, there would be an accompanying disturbance of other natural resources. Additional conventional onshore exploration and extraction of oil or natural gas, for instance, can cause the potential for fracturing of underground aquifers, soil erosion, decreased soil

fertility, and possible subsequent stream sedimentation (Department of Energy, 1980). Moreover, the mining, preparation, distribution and disposal activities associated with the production of synthetic fuel substitutes for natural gas can cause air quality and surface water deterioration and contamination of underground water supplies with saline mine water in addition to other natural and human resource concerns (Department of Energy, 1980). In addition, the increased consumption of natural gas resources for energy uses which could be met by electricity could reduce the availability of these resources for consumer uses where no feasible alternatives to natural gas exist.

Chapter V

Consultation and Coordination



V. Consultation and Coordination

A scoping process for an EIS is designed to allow the public to become involved in defining significant alternatives, issues, and potential impacts that would be evaluated in the draft EIS. On November 23, 1982, BPA published a Notice of Intent to Prepare an Environmental Impact Statement in the Federal Register (47 FR 52745). The notice invited written and oral comments on the scope of environmental issues to be considered in the EIS.

Between December 6 and 10, 1982, BPA staff also telephoned individuals and organizations who had participated in BPA's 1982 rate filing or who represented particular groups or government agencies with an interest in the 1983 rate filing. Those selected to receive the phone calls were taken from three lists: those who mailed substantive comments about the 1982 Draft EIS to BPA during the last rate filing; those who made significant contributions on the environmental impact statement in the last rate case formal hearing; those who had contacted BPA about the final EIS for the 1982 rate case. These individuals were contacted so that comments could be gained for use in scoping the EIS. Letters were sent to respondents acknowledging the information BPA received by phone or mail. Those who could not be contacted directly were mailed information including a copy of the list of topics proposed for inclusion in the Draft EIS from the preliminary Table of Contents and a list of scheduled events relevant to the 1983 rate case.

BPA published an EIS on its 1982 rate proposal in August 1982. Because the range of actions, impacts, and alternatives are similar to those pertaining to the 1983 rate proposal, BPA used that EIS to scope substantially the EIS for the 1983 rate proposal. No scoping meetings were held since five public hearing/scoping meetings had been held throughout the Pacific Northwest in the drafting of the 1982 EIS. At each of these hearings, BPA made a brief presentation about environmental considerations and the rate process and distributed a rate development schedule, suggested outline for the draft EIS, and summary of environmental issues and alternatives that had been identified at that time. All participants were given the opportunity to ask clarifying questions and to offer comments and suggestions. Only twenty-two people offered comments during the meetings.

BPA did not receive extensive comments on the 1983 Draft EIS. Not all of these comments addressed the document itself. Some comments were essentially clarifying questions and others were suggestions directed toward BPA policy and rate design. All comments and suggestions received were carefully considered by BPA staff in developing this Final EIS.

A list of commentators on the draft EIS and a summary of the comments and BPA's evaluation are presented in Chapter VI.

the 1990s, the number of people in the UK who are aged 65 and over has increased from 10.5 million to 12.5 million, and the number of people aged 75 and over from 4.5 million to 6.5 million (Office for National Statistics 2000).

There is a growing awareness of the need to address the needs of older people in the community. The Department of Health (1999) has published a strategy for older people, which sets out a vision for the future of older people's services. The strategy is based on the following principles:

- Older people should be able to live independently in their own homes for as long as possible.
- Older people should be able to access the services and support they need to live independently.
- Older people should be able to participate in the decisions that affect their lives.
- Older people should be able to live in a safe and secure environment.

The strategy also sets out a number of key objectives for the future of older people's services, including:

- To ensure that older people have access to the services and support they need to live independently.
- To ensure that older people are able to participate in the decisions that affect their lives.
- To ensure that older people live in a safe and secure environment.
- To ensure that older people are able to live in their own homes for as long as possible.

The strategy also sets out a number of key actions for the future of older people's services, including:

- To ensure that older people have access to the services and support they need to live independently.
- To ensure that older people are able to participate in the decisions that affect their lives.
- To ensure that older people live in a safe and secure environment.
- To ensure that older people are able to live in their own homes for as long as possible.

The strategy also sets out a number of key outcomes for the future of older people's services, including:

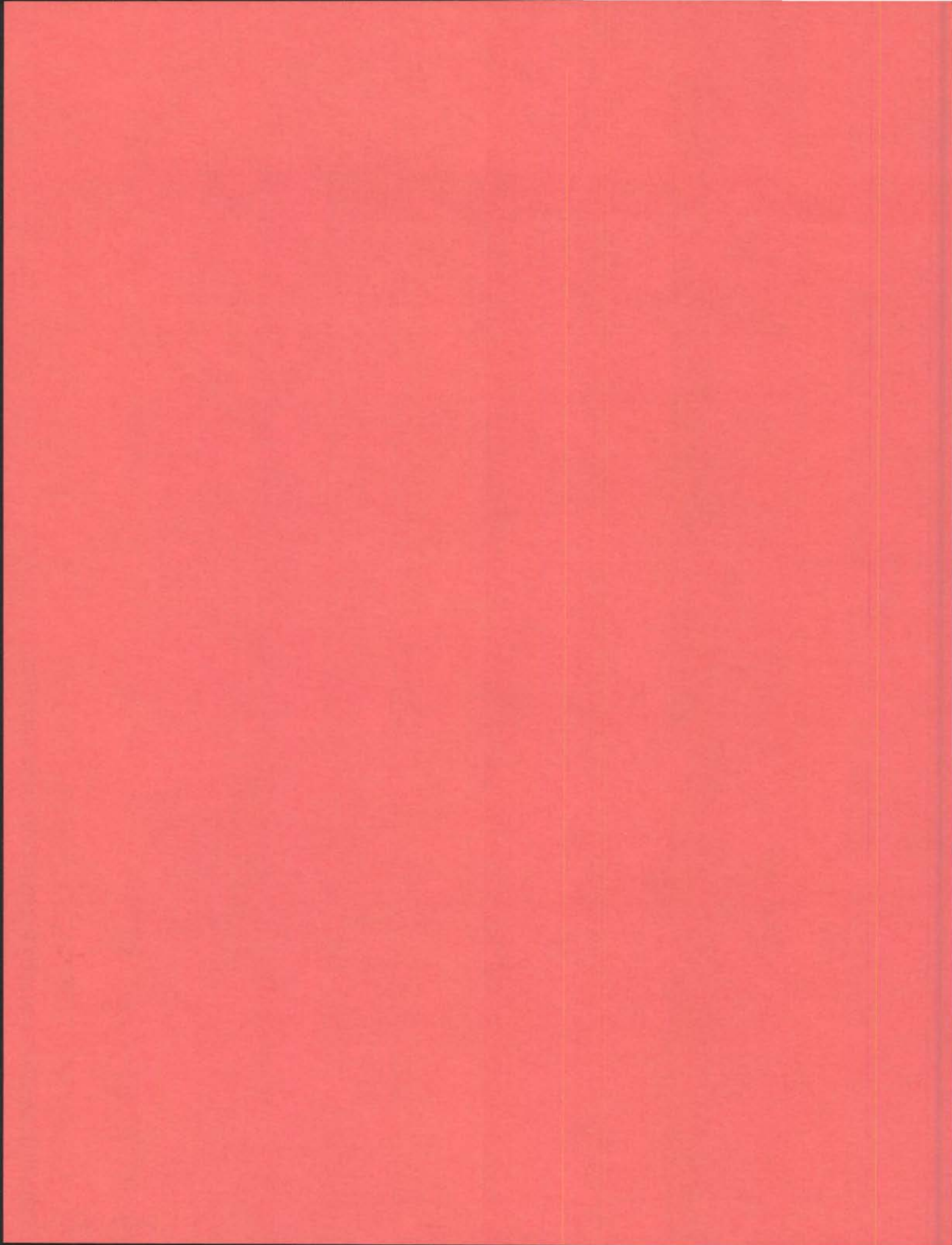
- To ensure that older people have access to the services and support they need to live independently.
- To ensure that older people are able to participate in the decisions that affect their lives.
- To ensure that older people live in a safe and secure environment.
- To ensure that older people are able to live in their own homes for as long as possible.

The strategy also sets out a number of key indicators for the future of older people's services, including:

- To ensure that older people have access to the services and support they need to live independently.
- To ensure that older people are able to participate in the decisions that affect their lives.
- To ensure that older people live in a safe and secure environment.
- To ensure that older people are able to live in their own homes for as long as possible.

Chapter VI

Comments and Responses



VI. Comment and Responses

BPA published its 1983 Wholesale Power Rate Draft Environmental Impact Statement in April 1983. Copies of the draft EIS were made available to all parties in the rate case, government agencies, local governments, BPA customers, interest groups, and interested members of the public. A 45-day period for public comment on the draft EIS commenced on May 13, 1983, with the Environmental Protection Agency's (EPA) "Notice of Availability" (48 FR 22790), and closed on July 5, 1983.

A list of parties submitting comments on the draft EIS is presented first in this chapter. The comments of each party follows. Finally, BPA's responses to them have been grouped by topic area. The topic areas and their location within this portion of the chapter are as indicated below.

- I. Irrigated Agriculture
- II. Direct Service Industrial Customers
- III. Southwest Customers
- IV. Miscellaneous

1983 Wholesale Power
Rates Proposal

<u>Individual/Organization</u>	<u>Page</u>
Big Bend Electric Cooperative, Inc. Ritzville, WA 99169	VI-4-6
Office of Planning and Research State Clearinghouse Sacramento, CA	VI-7
Lane Council of Governments Eugene, OR 97401	VI-8
Intergovernmental Relations Div. State of Oregon Salem, OR 97310	VI-9
Dept. of Transportation State of Oregon Salem, OR 97310	VI-10
State Clearinghouse Intergovernmental Relations Div. Salem, OR 97310	VI-11
U.S. Dept. of Agriculture Soil Conservation Service Portland, OR 97204	VI-12
U.S. Dept. of Agriculture Rural Electrification Administration Washington, D.C. 20250	VI-13
U.S. Dept. of the Interior Bureau of Land Management Spokane, WA 99202	VI-14
The Resources Agency of California State of California Sacramento, CA 95814	VI-15-18
Direct Service Industries, Inc. Lloyd Center Tower Portland, OR 97232	VI-19-20
Lane Council of Governments Eugene, OR 97401	VI-21-22
Los Angeles Dept. of Water and Power Los Angeles, CA 90051	VI-23-24

<u>Individual/Organization</u>	<u>Page</u>
Department of the Army North Pacific Div., Corps of Engineers Portland, OR 97208	VI-25
Dept. of Ecology State of Washington Olympia, WA 98504	VI-26
Dept. of Health & Human Services Public Health Service Atlanta, GA 30333	VI-27
U.S. Environmental Protection Agency Region X 1200 Sixth Ave. Seattle, WA 98101	VI-28
U.S. Dept. of the Interior Office of the Secretary Washington, D.C. 20240	VI-29-30
Gary Galbreath Ritzville, WA Field Hearing: Spokane, WA July 21, 1983	VI-31-34

BIG BEND *Electric* CO-OPERATIVE, INC.

RITZVILLE, WASHINGTON 99169

May 26, 1983

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

I have taken the time to review your draft EIS for the 1983 rate increase. As manager of a rural electric serving the largest share of irrigated agriculture in Washington state, I have given special attention to this subject. While I recognize this is a draft and you anticipate "substantially improved" estimates for use in the final EIS, I would make the following comments in hopes that your final EIS will be truly reflective of irrigated agriculture's current status and future prospects:

1. Page II-36 of 118, paragraph 2: In explaining why irrigation has increased since 1950, it should be noted that low electric rates and active promotion by BPA, with promises of stable rates in the future, played a key role.

2. Page II-37 of 118, paragraph 3: Your report often distinguishes between sprinkler and gravity irrigation methods, but not between surface and deep well irrigation. Where water has to be lifted from deep wells, some exceeding 1,000 feet, the energy requirements become much greater. The EIS should give special attention to irrigators with high lifts as they represent a unique class which is greatly impacted by increased power rates.

3. Page II-40 of 118, paragraph 1: In this section and others, the EIS refers to BPA's increased power generation potential if irrigated acreage is reduced. It should be noted that there is presently no market for this power and that BPA is historically surplus during much of the irrigation season. In fact, the present irrigation load on BPA fits the natural river flows and complements BPA's generation and transmission system. It would be to BPA's advantage were the irrigation load to increase. I am uncertain as to why statements like "...any reduction in irrigation load combined with the increase in generation capability increases the proportion of that capability which can be used to serve non-irrigation load...." are often included in the EIS. However, they appear to have little relation to the real world problems associated with energy cost increases.

4. Page II-40 of 118, paragraph 3, etc.: At this point the EIS

Electrifying

YOUR FARM AND HOME
VI-4

begins to paint a rosy picture for irrigated agriculture, noting that, "...no distinguishable differences in either total or new sprinkler irrigated acreage are projected to occur..." between rate levels 16.32 - 33.56 mills. The EIS goes on to show, in Table II-8, how, "Some new lands are brought under sprinkler irrigation regardless of the revenue level." It is further noted that, "By 2000, under those alternatives (including the proposed 1983 rate increase), the amount of dry land converted to sprinkler irrigation increases 100 percent."

These assumptions must be challenged in light of current trends. In recent years BPA wholesale rates have increased dramatically, causing increases at the retail level. During that period Big Bend Electric Cooperative has experienced a gradual decline in irrigation sales, plus a loss of some irrigation accounts. We can only believe that this trend will accelerate if power rates continue to climb. Other BPA preference customer utilities have seen greater irrigation load reductions.

It would be nice to be able to place our confidence in your forecast of continued irrigation development despite increasing electric rates. However, because we live in a farm community where irrigation is the cornerstone of all agribusiness, we cannot overlook the changes that are currently taking place. Irrigators are already going out of business--in greater numbers than during the Great Depression. Deep well irrigators are particularly hard hit. Farm prices are depressed. Land that once sold for \$2,000 per acre is currently going unsold at \$1,000 per acre. It's a buyer's market for irrigated farms in BPA territory, especially if the water must be drawn from deep wells.

5. Page III-72 of 73, paragraph I: Again, recent evidence contradicts your statement, "...BPA's proposed wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production..." Irrigated land is already going out of production and energy costs is one of the main factors.

6. Page III-73 of 73, line 2: Your choice of words, "slightly depressed," is interesting. Is BPA aware of agriculture's place in the economy of the Northwest? I don't believe, as the EIS seems to imply, that we are looking at a slight erosion of irrigated agriculture if the worst case scenario takes place. I think the evidence speaks for itself and that we are looking at a steep downward drop in irrigated acreage if BPA rates increase again--even slightly! I'm surprised and greatly concerned that the EIS seems out-of-touch with current events and is optimistic beyond all reason concerning the future of irrigated agriculture. I can only hope that the linear programming model that is being developed by Northwest Economic Associates relates better to the real world.

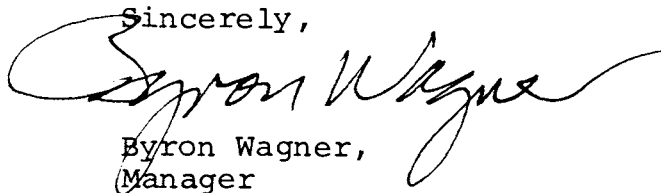
7. Page IV-140 of 147, paragraph 2: This paragraph speaks to BPA's proposed changes in summer energy and demand rates which will benefit irrigators. These improvements are greatly needed and gratefully acknowledged. However, the EIS should consider the impacts of a separate irrigation rate as part of the priority firm rate. Because irrigation is a unique seasonal load that does match BPA's hydro resources, such a rate could be beneficial to the region. It

should be considered in the final EIS.

8. Page V-15 of 17, entire page: No evaluation of comments received would have been more appropriate considering the superficial evaluation that was offered. Most statements are poorly conceived and do not speak to the real issues. The comment that the low density discount "...may provide some revenue assistance through a lower priority firm rate..." is unreasonable in that the LDD does not take into account the fallout from Supply System plants #4 and #5 or revenue shortfalls from decreasing irrigation sales. However, if this statement was included to imply that BPA is interested in considering expansion of the LDD to help remedy such problems rural utilities face, then Big Bend Electric Co-op is in 100% agreement.

In closing, let me point out that this letter is not intended to be critical of the effort made to determine impacts of the proposed rate increase. My motivation has been to point out some things using a different point of view and to offer suggestions that may or may not be of interest to you and your staff. The more realistic your EIS is, the more realistic BPA's planning for the future will be--including its decisions relating to wholesale rates. Therefore, we must all do our part to see that best efforts are made to determine the real impacts associated with BPA activities.

Sincerely,

A handwritten signature in cursive script, appearing to read "Byron Wagner", written in dark ink. The signature is fluid and extends across the width of the typed name below it.

Byron Wagner,
Manager

ACKNOWLEDGEMENT

State of California
Department of Fish and Game
Division of Fish Management
1515 L Street, Sacramento, CA 95833

TITLE: BONNEVILLE POWER ADMINISTRATIO
N 1983 WHOLESALE POWER RATE
STATE CLEARINGHOUSE NUMBER: 83051603
REVIEW STARTS: 05/20/83
REVIEW ENDS: 07/01/83
CONTACT: NORMA WOOD
(REVIEW STARTS ON NEXT DAY WHEN DOCUMENT IS
RECEIVED AFTER 10:00 A.M.)

Please use the State Clearinghouse Number on future correspondence with this office and with agencies approving or reviewing your project.

This card does not verify compliance with environmental review requirements. A letter containing the State's comments or a letter confirming no State comments will be forwarded to you after the review is complete.

LCOG Lane Council of Governments

NORTH PLAZA LEVEL PSB / 125 EAST EIGHTH AVENUE / EUGENE, OREGON 97401 / TELEPHONE (503) 687-4283

May 18, 1983

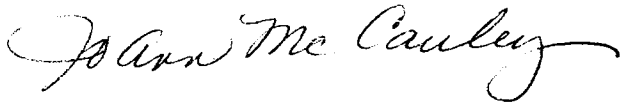
Anthony R. Morrell, Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

SUBJECT: AREAWIDE CLEARINGHOUSE REVIEW
TITLE: 1983 Wholesale Power Rate Draft (EIS)
CLEARINGHOUSE NUMBER: 2E99

The above notification has been received and is currently undergoing areawide clearinghouse review. If you wish to contact our office about the proposal, please refer to the Clearinghouse Number.

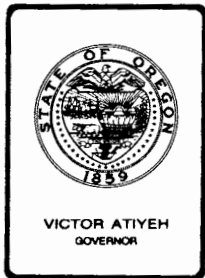
Your proposal will be formally considered by the Lane Council of Governments (L-COG) Board of Directors on Thursday, June 23, at 7:30 p.m. in the City of Creswell Community Center. You are welcome to attend. The action of the L-COG Board will be forwarded to you, along with documentation of comments received, following the meeting. If the Board defers action on your proposal, you will be notified.

Sincerely,



JoAnn McCauley
Information Coordinator

cljma95



Executive Department

155 COTTAGE STREET NE., SALEM, OREGON 97310

OFFICIAL FILE COPY	
No.	Date JUN 23 1983
Referred to:	
Action Taken	
☐ ANS.	☐ NO REPLY
By	Date

June 21, 1983

Mr. Peter Johnson, Administrator
Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Subject: Bonneville Power Administration 1983 Wholesale Power
Rate Increase
PNRS # OR830513-107-4

Dear Mr. Johnson:

Thank you for submitting your draft Environmental Impact Statement for State of Oregon review and comment.

Your draft was referred to the appropriate state agencies for review. The consensus among reviewing agencies was that the draft adequately described the environmental impact of your proposal.

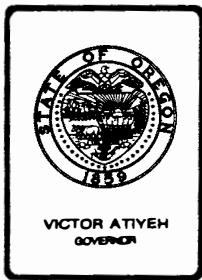
We will expect to receive copies of the final statement as required by Council of Environmental Quality Guidelines.

Sincerely,

INTERGOVERNMENTAL RELATIONS DIVISION

Dolores Streeter
A-95 Coordinator

DS:bm
Enclosures



Department of Transportation

PARKS AND RECREATION DIVISION

525 TRADE STREET SE., SALEM, OREGON 97310

June 3, 1983

Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

State Parks and Recreation Division would like to express their appreciation for the opportunity to review the BPA 1983 Wholesale Power Rate Draft EIS. The division itself does not have any major concerns with the DEIS. However, we would like to point out some discrepancies found on Pages 3-26 concerning significant natural features surrounding DSI customers. Under the listing of State Parks in Oregon, and State Forests, you should be aware that Cascadia, Deschutes River and Hat Rock are all State Parks. They are not State Forests. Elliott State Forest is properly placed within that category. Furthermore, Crater Lake National Park is not found within Douglas County, it is located in Klamath County. We are unclear as to what the intent of providing Table III-5 is. If it is just to give example of those types of natural features that may be found, that would be adequate. However, if it is an attempt to address all known significant natural features and major recreation areas, it falls somewhat short. The Columbia River Gorge which would be in the vicinity of the majority of the DSI plants in Oregon, has a number of State Parks and U.S. Forest Sites, which have extreme natural and aesthetic values. Should not all these be listed also?

Sincerely,

Alan J. Cook
State Recreation Planner

AJC:tla



OREGON PROJECT NOTICE ACKNOWLEDGEMENT

State Clearinghouse
Intergovernmental Relations Division
155 Cottage Street N.E.
Salem, Oregon 97310

Phone (503) 378-3732 or Toll Free in Oregon 1-800-452-7813

APPLICANT: Bonneville Power Admin.

Your project notice was circulated
to state agencies checked below:

PROJECT TITLE: 1983 Wholesale Power Rate Increase

ECONOMIC DEV. & CONSUMER SVCS

DATE RECEIVED: May 13, 1983

X Agriculture

PNRS # OR 830513-107-4

X Soil and Water

— Economic Development

— Fire Marshal

— Housing

— Labor

— Real Estate

EDUCATION

— Education

— Educ. Coordinating

— Higher Education

EXECUTIVE

— Budget

HUMAN RESOURCES

— Adult and Family Services

— Children's Services

— Community Services

— Corrections

— Employment

— Health

— Mental Health

— Senior Services

— Vocational Rehabilitation

NATURAL RESOURCES

X Governor's Office

X DEQ

X Energy

X Fish and Wildlife

X Forestry

X Geology

X Lands

X LCDC

X Water Resources

TRANSPORTATION

— Aeronautics

— Director

— Highway Division

— Historic Preservation

— Parks Division

— Public Transit

MISCELLANEOUS

— Dev. Disabilities Council

— Extension Service

— Other

Your project notice has been assigned the
file title and number that appear above.
Please use it in correspondence and, if
applicable, enter it in Block 3A on the
424 form for the project. Your project
notice must also be submitted for review
to any affected areawide clearinghouse.

A. FEDERAL GRANTS

☐ Initial 30 day review of your notice
of intent to apply for grant funds
began on above date.

☐ 30 day review of your final grant
application began on above date.

B. HUD HOUSING

☐ Initial 30 day review began on the
above date.

C. DIRECT FEDERAL DEVELOPMENT

☐ Initial 30 day review.

D. ENVIRONMENTAL IMPACT STATEMENT

☒ Initial 45 day review of draft EIS
began on above date.

☐ 30 day review of final EIS began
on the above date.

E. STATE PLAN/AMENDMENT

☐ 45 day review began on above date.

State Clearinghouse use only:

St. Agency Due Date: _____

Federal Agency: _____

County: _____



United States
Department of
Agriculture

Soil
Conservation
Service

1220 S. W. Third Avenue
16th Floor
Portland, Oregon 97204

May 19, 1983

Anthony R. Morrell, Environmental Manager
Bonneville Power Administration
P O Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

We have reviewed the Bonneville Power Administration 1983 Wholesale Power
Rate Draft Environmental Impact Statement and have no comments or suggestions.
You have adequately covered all environmental concerns.

JACK P. KANALZ
State Conservationist

Acting

Attachment



The Soil Conservation Service
is an agency of the
Department of Agriculture



United States
Department
of Agriculture

Rural
Electrification
Administration

Washington
D.C.
20250

SUBJECT: SJ-1983 Wholesale Power Rate
Draft Environmental Impact Statement

10 JUN 1983

TO: Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

The Rural Electrification Administration (REA) has been asked to review the Draft Environmental Impact Statement (DEIS) (1983 Wholesale Power Rate) distributed by Mr. Peter T. Johnson's letter of May 10, 1983.

The REA review was not exhaustive but did not result in any comments on the DEIS itself.

Thank you for the opportunity to review the DEIS. It will be retained in REA's files.

WILLIAM E. DAVIS
Director
Western Area - Electric



United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Spokane District Office
East 4217 Main Avenue
Spokane, Washington 99202

IN REPLY
REFER TO:

1792 (130.1)

June 9, 1983

Bonneville Power Administration
Anthony R. Morrell
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

We have reviewed your draft EIS on Bonneville Power Administration 1983 Wholesale Power Rate. We find the document thorough and complete. Thank you for the opportunity to review the EIS.

Sincerely yours,

Gary J. Yeager
Environmental Coordinator

Resources Building
1416 Ninth Street
95814

(916) 445-5656

GEORGE DEUKMEJIAN
GOVERNOR OF
CALIFORNIA



THE RESOURCES AGENCY OF CALIFORNIA
SACRAMENTO, CALIFORNIA

Air Resources Board
California Coastal Commission
California Conservation Corps
Colorado River Board
Energy Resources Conservation
and Development Commission
Regional Water Quality
Control Boards
San Francisco Bay Conservation
and Development Commission
Solid Waste Management Board
State Coastal Conservancy
State Lands Commission
State Reclamation Board
State Water Resources Control
Board

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
Post Office Box 3621
Portland, OR 97208

June 28, 1983

Dear Mr. Morrell:

The State has reviewed the draft environmental impact statement, Bonneville Power Administration 1983 Wholesale Power Rate, submitted through the Office of Planning and Research in accordance with OMB Circular A-95 and the National Environmental Policy Act of 1969.

This review was coordinated with the Energy and Public Utilities Commissions, Air Resources and State Water Resources Control Boards, and the Departments of Food and Agriculture and Water Resources.

The only comments received from the State's departments, boards, and commissions which reviewed this document were those of the Energy Commission. The Commission's remarks, contained in its letter of June 24, 1983, are attached for your consideration in preparing the final EIS for this project.

We appreciate having been given an opportunity to review this report and to comment upon its contents.

Sincerely,

A handwritten signature in cursive script, reading 'Gordon F. Snow'.

GORDON F. SNOW, Ph.D
Assistant Secretary for Resources

Attachment

cc: Office of Planning and Research
1400 Tenth Street
Sacramento, CA 95814

(SCH 83051603)

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET
SACRAMENTO, CALIFORNIA 95814



June 24, 1983

Gordon F. Snow
Assistant Secretary
Resources Agency
1416 Ninth Street
Sacramento, CA 95814

Dear Mr. Snow:

BONNEVILLE POWER ADMINISTRATION 1983 WHOLESALE POWER RATE,
DRAFT EIS, SCH #83051603

The California Energy Commission appreciates the opportunity to review the Bonneville Power Administration (BPA) Draft EIR and offers the following comment.

While the Draft EIS discusses in detail the impacts of the proposed 1983 wholesale power rate within the Pacific Northwest, no serious attempt has been made to quantify the impacts in California or the other states of the Southwest that provide alternative markets for Northwest Power. The analysis also fails to recognize that the level and predictability of BPA's rates help determine the availability of surplus power and the cost-effectiveness of new transmission capacity between California and the Northwest. Additional, detailed comments follow.

- o p. II-13 The summary of the impacts of alternative revenue levels excludes socioeconomic impacts not directly related to rates. For example, the construction and operation of power plants will require expenditures for local public services such as schools and roads.
- o p. II-14 The analysis of effects on demand for electricity covers only regional (Northwest) demand. Under the LRIC pricing alternative, more electricity would be available for export, so that total demand (including export areas) would decline less than shown here, possibly remaining the same.

- o p. II-25 The DEIS notes that, "impacts of BPA revenue increases on the retail rates of Pacific Southwest utilities were addressed in the Final Environmental Impact Statement, 1979 Wholesale Rate Increase." There is no explanation why the impacts of the 1983 rate increase would be the same as those of the 1979 rate increase.
- o pp. II-29-30 This discussion of effects on low-income consumers applies only to Pacific Northwest consumers. If the LRIC were below the incremental costs of California utilities' supplies, the LRIC alternative could reduce retail rates for low-income and other California consumers.
- o p. II-36 The DEIS does not discuss the impacts of the rate alternatives on irrigated agriculture in California.
- o pp. II-62-3 The "projected environmental impacts of implementation of proposed rates" apply only to the Northwest. There should be some discussion of the out-of-state impacts of not only those rates which apply to out-of-state users but also the increased or decreased availability of surplus power.
- o p. II-102 The DEIS correctly notes that, "purchasers could use surplus firm power to shut down high-cost oil or other thermal generation, or could delay completion of other generation now under construction. This could reduce overall power costs to purchasing utilities, thereby reducing retail rates." However, the noted impact is that of the surplus firm power rate itself, not of the proposed changes. It is not clear what the impact of the proposed changes on California utilities or retail consumers would be.
- o p. II-109-115 Again, the DEIS does not state the impacts of the revised non-firm energy rate schedules on consumers outside of the region.
- o p. IV-3-4 This discussion of "BPA's Load and Resource Modeling Processes" does not mention energy supply and demand in the areas to which BPA power is exported.
- o p. IV-15 The DEIS states that the least cost resource mix model, "gives only limited treatment to the seasonality of loads and resource output and to better than critical hydro-conditions." Use of the model could understate seasonal energy surpluses and shortages and, hence, understate the benefits of sales to and purchases from utilities in other regions.

June 24, 1983

IV-56 The DEIS indicates a sudden reduction in DSI (direct service utility) loads if the long-run incremental cost pricing alternative were adopted. This implies severe local socioeconomic impacts could occur. However, the analysis assumes a sudden jump of rates from 27.5 mills per kilowatt-hour to 42.6 mills per kilowatt-hour. A more realistic LRIC alternative would assume a gradual increase in rates which could mitigate the local socioeconomic impacts.

p. IV-131 BPA considers conservation measures costing less than 35 mills per kilowatt-hour as cost-effective, apparently based on the LRIC analysis. The DEIS should recognize that higher levels of conservation will be cost-effective if the power conserved can be sold out-of-state at a price higher than the cost of conservation.

p. IV-142 Inasmuch as mitigation measures were not identified, the discussion of unavoidable adverse impacts should include out-of-state impacts.

If you have any questions concerning our review, please call Cheri McFarland at (916) 324-3197.

Sincerely,



E. ROSS DETER, Chief
Siting and Environmental
Division

ERD:CMcF:tdw

DIRECT SERVICE INDUSTRIES, INC.

1290 Lloyd Center Tower • 825 N.E. Multnomah Street
Portland, Oregon 97232
(503) 233-4445

July 5, 1983

Mr. Anthony R. Morrell, Environmental Manager
Bonneville Power Administration
P. O. Box 3621 - SJ
Portland, OR 97208

Dear Tony:

The DSIs have few substantive comments on Bonneville Power Administration's 1983 Wholesale Power Rate Draft Environmental Impact Statement. However, we want you to know that the DSIs appreciate Bonneville dedicating sufficient staff time and research to consider the impacts that rising power costs have had, and will have, on DSI operations. The summaries of impacts loss of DSI loads would have on BPA power operations, rates for other power groups, local and regional jobs and their economies also are important factors. Bonneville staff has covered these items in considerable depth for which we are appreciative.

As you know, the DSIs commissioned Battelle Pacific Northwest Laboratories to conduct an independent study of "The Direct Service Industries: Their Contribution to the Northwest Power System and Economy." The Battelle study and BPA's own EIS both show that DSI rates have become uncompetitive and that this could adversely impact BPA and all its customers. A copy of the Battelle study is enclosed for inclusion in the rate record.

Our text-specific comments/corrections are:

Page 8, Line 10

As PNUCC has indicated in its comments on BPA's Environmental Assessment for the Water Budget, we believe the water budget will result in more than a 1 mill/kWh increase in the Priority Firm rate. It also may adversely affect "combination service" for the DSI top quartile loads, as we mentioned in our comments on that EA.

Page 2-18, Line 3

A typo "13" should be "is".

Page IV-26, Figure IV-1

Lines on the map showing plant locations for the plants 13 through 17 are not very accurate.

Page IV-27, Line 22

"11 existing aluminum plants" should be changed to read "10 existing aluminum reduction plants".

Mr. Anthony R. Morrell

July 5, 1983

Page 2

Page IV-29, Table IV-3, Line 1, Column (C)
Insert a comma after "Primary Aluminum"

Line 11, Column (C)
Change to read "Primary Aluminum, Rod, Wire & Cable"

Line 14, Column (C)
Change to read "Magnesium & Ferrosilicon"

Page IV-32, Line 3
Nonfirm energy is offered to Northwest preference customers ~~pursuant-to-P.L.-88-552~~ before it ~~can-be~~ is used to serve DSI loads during the pendency of the U.S. Supreme Court consideration of the Ninth Circuit Court decision in Central Lincoln I.

Page IV-32, Line 18
...DSIs have borrowed on their firm energy as previously discussed, ~~and~~ subsequent stream flows don't restore the reservoirs and the energy is needed by BPA to meet its firm obligations.

Page IV-34, Line 13
Change the word "deficients" to "deficits".

Page 36, Line 24
Replace the word "reduced" with "eliminated".

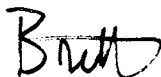
Page IV-37, Line 9
Special emphasis is focused on ~~BPA's-11~~ the 10 aluminum smelters BPA serves.

Pages IV-54 to 58
We believe the forecasts of DSI loads produced by BPA's simulation model are too high. This may result largely from BPA's optimistic outlook on improvement in the aluminum market. If DSI power costs continue in the upper 25 to 40 percent of world power costs, the operating levels BPA predicts are unlikely to be attained.

Page IV-57, Line 16
Insert "non aluminum" before "DSIs".

Again, we appreciate BPA's staff work in analyzing the impact BPA's increased rates are having on DSI operations in the Pacific Northwest.

Sincerely,



Brett E. Wilcox
Executive Director

AREAWIDE CLEARINGHOUSE CONCLUSIONS

APPLICANT: Bonneville Power Administration

PROJECT TITLE: 1983 Wholesale Power Rate

L-COG REFERRAL:# 2E99

DATE: June 24, 1983

The L-COG Areawide Clearinghouse has reviewed your proposal and finds it to be:

Consistent with or supportive of areawide planning.

Consistent, pending resolution of concerns. See comments.

Inconsistent with areawide planning. See comments.

Accordingly, the Clearinghouse has taken the following action:

Recommends support.

Does not recommend support. See comments.

Recommends support, conditional on resolution of concerns. See comments.

X Makes no comment.

Transmit the comments received

L-COG Review Comments:

See attached comments:

/FORMS1/ACC1

 Lane Council of Governments
NORTH PLAZA LEVEL PSB / 125 EIGHTH AVENUE EAST / EUGENE, OREGON 97401

Springfield.

Comments Requested From: Cities of Eugene and ~~Eugene~~. EWEB, SUB and Lane County.

Comments Received: EWEB recommended approval with the condition that, as a formal party to BPA's 1983 wholesale power rate adjustment hearings process, EWEB will address the adequacy of the EIS during the formal hearings.

Springfield submitted no comment.

L-COG Staff Comments: The draft EIS thoroughly addresses the environmental impacts associated with the wholesale rate alternatives. Of equal interest are the socioeconomic impacts associated with the proposed rate increases. The average 27 percent rate increase could have significant impacts upon local economies, especially low income households and recession-weakened businesses. BPA asserts that its preferred rate hike proposal has been designed to minimize impacts upon these groups. In addition, BPA suggests that residential and commercial conservation programs would serve to mitigate the impacts of the proposed rate increase.

OFFICE OF
CITY ATTORNEY

IRA REINER
CITY ATTORNEY



EDWARD C. FARRELL
CHIEF ASSISTANT CITY ATTORNEY
FOR WATER AND POWER

DEPARTMENT OF WATER AND POWER
111 NORTH HOPE STREET • P.O. BOX 111
LOS ANGELES, CALIFORNIA 90051
TELEPHONE (213) 481-6362

July 6, 1983

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - SJ
Portland, Oregon 97208

Re: Comments on BPA 1983 Wholesale Power Rate Draft
Environmental Impact Statement - April, 1983

Dear Mr. Morrell:

I spoke with Ms. Linda Burbach, your Manager Assistant, regarding comments which the City of Los Angeles Department of Water and Power wish to make on the above-captioned draft EIS. Ms. Burbach assured me that comments received by Bonneville on Friday, July 8, 1983, would be fully considered in preparation of the final EIS. Therefore, we submit the below comments which we understand will be considered by Bonneville to have been timely filed. Comments were not submitted on July 5, due to the undersigned's illness.

In our trial brief of May 31, 1983, in the 1983 BPA Rate Proceeding, we briefly addressed at pages 11 and 12 inadequacies of the draft EIS. Therefore, wholly apart from these comments below, we have placed Bonneville on notice of several of our concerns regarding the adequacy of the draft EIS.

However, we wish again to emphasize that a supplement to the draft EIS or a "final" EIS allowing for public comment and response by BPA must address all potential environmental impacts of the proposed transmission rates, the transmission access adders (only during Cross-Examination finally stated to be a proposal at 4.5 mills), and the proposed elimination of the spill rate. In that Bonneville has not addressed these three items in the draft EIS, we shall not undertake to set forth what the many potential environmental impacts of each of these proposals is or may be. That is clearly Bonneville's responsibility. However, we expect that any subsequent environmental impact document, whether a supplement to the draft EIS or a "final" EIS, must fully address these three issues and provide adequate time for public comment on each of these proposal's potential environmental impacts.

Mr. Anthony R. Morrell
Environmental Manager

July 6, 1983
Page Two

Failure to fully consider all environmental impacts of the aforementioned proposals in this 1983 rate proceeding would appear to violate the following laws, regulations:

The National Environmental Policy Act (NEPA) (42 U.S.C. 4321, et-seq., the Council on Environmental Quality (CEQ) Regulations for Implementing the Provisions of NEPA (40 C.F.R. parts 1500 - 1508), the Department of Energy's final guidelines for compliance with NEPA (45 C.F.R. 20649, March 28, 1980), among other applicable statutes, regulations and executive orders.

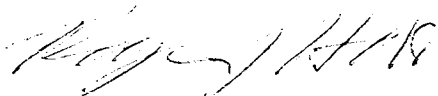
We are also seriously concerned as to the timing of the draft EIS in connection with the proposed wholesale and transmission rates. For example, determination by BPA that the transmission access adder is a "proposal" only as late as Cross-Examination raises serious concerns as to the nature and scope of BPA's proposed rates and the adequacy of its environmental analysis of its "proposal." See Aberdeen & Rockfish R. Co. v. S.C.R.A.P. (1975) 422 U.S. 289, 320, 45 L. Ed 2d 191, 95 S.Ct. 2336.

Any questions regarding these comments should be addressed to Roger J. Holt, 111 North Hope Street, Los Angeles, California 90012, (213) 481-6302.

Very truly yours,

IRA REINER, City Attorney
EDWARD C. FARRELL, Chief Assistant
City Attorney for Water and Power

By


ROGER J. HOLT
Assistant City Attorney

RJH:vm



DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION, CORPS OF ENGINEERS
P.O. BOX 2870
PORTLAND, OREGON 97208
June 28, 1983

Environmental Resources Branch

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621 SJ
Portland, Oregon 97208

Dear Mr. Morrell:

This is in response to Mr. Peter Johnson's May 10, 1983 letter requesting our review of your 1983 Wholesale Power Rate Draft Environmental Impact Statement (EIS).

We have reviewed the EIS and make the following comments.

a. Page II-75 of 118, lines 12-16. The conclusion that combustion turbines will most likely supply additional peaking needs is premature. The Corps of Engineers, Bureau of Reclamation, and mid-Columbia PUD's have and are studying adding peaking units to existing hydroelectric projects. When the need for peaking capacity approaches, adding units to existing hydro projects will be compared with combustion turbines. Then the decision can be made based on economics.

b. Page IV-59 of 147, line 26. The sentence refers to small hydroelectric as a potential resource to meet regional generation needs. Adding units to existing hydroelectric projects does not fit into the "small hydroelectric" definition as discussed on pages IV-65, 66, 67 of 147. We suggest either the reference to small be deleted or an additional discussion be added for hydroelectric projects larger than 15 Mw.

We appreciate the opportunity to review and comment on the EIS.

Sincerely,

A handwritten signature in cursive script, reading "Robert L. Henny", is written over the typed name.

Robert L. Henny
Assistant Chief, Planning Division

JOHN SPELLMAN
Governor



DONALD W. MOOS
Director

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

Mail Stop PV-11 • Olympia, Washington 98504 • (206) 459-6000

June 30, 1983

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Morrell:

Thank you for the opportunity to review the draft environmental impact statement for the 1983 wholesale power rate. We coordinated the review of this EIS with the other state agencies and received no specific comments on the proposal. We would, however, like to see the final EIS when it is issued.

If you have any questions, please call me at (206) 459-6237.

Sincerely,

A handwritten signature in cursive script that reads "Greg Sorlie".

Greg Sorlie
Environmental Review Section

GS:pp



DEPARTMENT OF HEALTH & HUMAN SERVICES

Public Health Service

Centers for Disease Control
Atlanta GA 30333

June 24, 1983

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

We have reviewed the Draft Environmental Impact Statement (EIS) for the Bonneville Power Administration 1983 Wholesale Power Rate. We are responding on behalf of the U. S. Public Health Service. We have no specific comments to offer at this time on the Draft EIS.

We appreciate the opportunity to review the Draft EIS and the consideration given to our December 17, 1982, scoping comments requesting an evaluation of indoor air quality effects and vector impacts due to reduced farming and maintenance of irrigation drainage facilities.

Sincerely yours,

A handwritten signature in dark ink, which appears to read "Frank S. Lisella", is written over a circular stamp. The signature is fluid and cursive.

Frank S. Lisella, Ph.D.
Chief, Environmental Affairs Group
Environmental Health Services Division
Center for Environmental Health

U.S. ENVIRONMENTAL PROTECTION AGENCY

REGION X

1200 SIXTH AVENUE M/S 443
SEATTLE, WASHINGTON 98101



REPLY TO
ATTN OF:

M/S 443

JUN 24 1983

Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

RE: Bonneville Power Administration 1983 Wholesale Power Rate Draft
Environmental Impact Statement (EIS)

Dear Mr. Morrell:

The Environmental Protection Agency (EPA) has reviewed the subject Draft EIS. We find that the document presents a comprehensive analysis of the environmental impacts associated with varying electrical rates and energy consumption. The actual rate changes proposed, however, were not readily apparent. We suggest that, for the benefit of the lay citizen who may review this document, BPA provide the information on existing rate schedules and proposed changes (particularly pg. II-59 to II-118) in tabular form to accompany the discussion in the text.

Based upon our review, we have rated this EIS LO-1 (LO - Lack of Objections; 1 - Adequate Information).

We appreciate the opportunity to review this EIS.

Sincerely,

A handwritten signature in dark ink, appearing to read "L. Edwin Coate", with a long horizontal flourish extending to the right.

L. Edwin Coate
Acting Regional Administrator



United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

ER 83/638

JUL 15 1983

Mr. Anthony R. Morrell
Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Morrell:

Thank you for Peter T. Johnson's letter of May 10, 1983, transmitting copies of the Bonneville Power Administration's 1983 Wholesale Power Rate draft environmental impact statement for review. Our comments are presented according to the format of the statement or by subject.

Effects on Irrigated Agriculture (II.B.3.f)

It is difficult to assess the validity of the conclusions in the statement regarding the effects of alternative prices of electrical power on irrigated agriculture without knowing the prices paid for production inputs and prices received for crops which were used in the NADP model. We have difficulty accepting the conclusion that the amount of sprinkler-irrigated land will increase by about 30 percent by the year 2000 for the proposed revenue level alternative. This is especially difficult to understand in view of the fact that this is the same level of development as is shown for the base rate and no action price alternatives.

Table II-8, on page II-44, indicates that a substantial amount of gravity service land will be converted to sprinkler service in spite of an increase in pumping power costs. We have difficulty in understanding the rationale for that prediction. Through the use of gated pipe systems, land that is gravity irrigated can obtain substantially improved labor and water efficiencies at half or less the investment cost of sprinklers and at a small fraction of the annual costs.

Areas of Particular Concern (III.B)

This section discusses several factors which would adversely affect fish and wildlife resources. These factors are directly applicable to wholesale power rate adjustments which would alter demand for power, thus affecting operation of the Columbia River dams. The resultant changes in river operations would in turn influence flows and water quality directly affecting fish and wildlife resources (e.g. increased turbine mortality and nitrogen poisoning of juvenile salmonids). However, under Environmental Consequences, Chapter IV there is no discussion describing what effects each alternative would have on fish and wildlife resources. Therefore, the final EIS should present information describing the potential adverse impacts on fish and wildlife resources for each alternative.

Air Quality (III.B.f.1)

Burning of wood for home heating is identified as one of the two major activities being undertaken by consumers to reduce power costs. Table II-4 (on page II-16) does not reflect this activity. Since wood burning is cited (page III-33, first sentence) as a major source of air pollution in the region, the statement should contain an estimate of the effect of alternative electrical rates on the burning of wood for space heating.

Socioeconomic Environment (III.B.2.c)

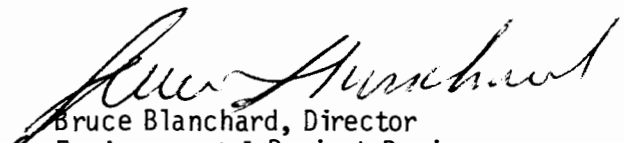
The first paragraph on page III-72 includes the statement "...BPA's proposed wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production, as other farmers would purchase the land put up for sale by the marginal farmers." Further supportive data is needed for this statement. Without knowing the income-cost relationships assumed in the model, it is difficult to assess its validity.

Currently, some farmers pumping from deep wells and/or with high pump lifts from surface sources are in severe financial trouble, in part due to pumping power costs. Increased power costs are not going to make this situation better, and we think it is reasonable to believe that these costs, along with continued price increases in fertilizer, pesticides, machinery, etc., could bring about a financial situation which even superior management may not overcome.

The second paragraph on page III-72 points out that farmers are unable to pass along increases in production costs to consumers of their products. No doubt some of the increased power costs will be offset by advances in irrigation technology and management, but certainly not all. Unless prices received for farm products improve substantially, we believe farmers will be unwilling and/or financially unable, in the face of rising power costs, to convert dryland to sprinkler service at the rate shown in the statement for the proposed price alternative.

We hope these comments will be helpful to you in the preparation of a final statement.

Sincerely,


Bruce Blanchard, Director
Environmental Project Review

1 in services and ability to meet taxpayer demands.

2 I urge you to approach any rate increase
3 with considerable caution and wariness.

4 MR. HARLOW: Thank you, Mr.
5 Coon.

6 Next is Gary Galbreath.

7 MR. GALBREATH: Mr. Harlow, Director Ellis,
8 fellow ratepayers: My name is Gary Galbreath. Along
9 with my mother and two brothers, I farm both irrigated
10 and dryland in the Ritzville area. Our family farm is
11 served by Big Bend Electric Cooperative, and I serve on
12 the Co-op's board of directors. I have testified at pre-
13 vious BPA hearings, as have dozens of other farmers and
14 agriculture experts, but it seems like BPA never gets
15 the message. Either that or BPA doesn't believe us when
16 we say irrigators are in trouble and power rates are a
17 main cause.

18 I would cite Bonneville's Draft Environmental
19 Impact Statement dated April 1983 as an example of the
20 problem. The report paints a rosy picture for irrigated
21 agriculture forecasting steady growth through the year
22 2000, with little consideration given to the current
23 problems irrigators face. In fact, the report, on page
24 72 of Section 3, states, "BPA's proposed wholesale power
25 rate increase is not expected to actually cause any

1 irrigated land to be taken out of production."

2 As an irrigator who is already reducing
3 irrigated acreage, I must disagree with BPA's assessment.
4 As a director of a rural electric co-op that has seen
5 irrigation sales dwindle in recent years, I would again
6 challenge BPA's assessment.

7 No one should be misled into thinking that
8 BPA wholesale power rates have not been a tremendous problem
9 for irrigators — They have been! As BPA rates have more
10 than tripled in recent years, power costs as a part of
11 overall operating costs have increased from between 3
12 and 7 percent to between 10 and 25 percent for the average
13 farmer. At a time when commodity prices have been stag-
14 nant, the electric rate increases have pushed many good
15 farmers to the brink of financial disaster.

16 Yes, fertilizer, equipment, fuel and other
17 costs have increased, too, but none as rapidly as
18 electricity.

19 True, crop prices have been poor, and this
20 compounds the problem, but these and other problems do
21 not erase the fact that electric rates have inflated to
22 the breaking point for most irrigators.

23 Our family was fortunate enough to sell
24 some irrigated acreage last year, and we would sell the
25 rest tonight if we could find a buyer, but what was a

1 seller's market has turned into a buyer's market.
2 Irrigated farmland is being discounted, due to the future
3 cost of energy -- not only due to recent increases but
4 because of the great uncertainty that exists.

5 Let me assure every BPA official that the
6 future cost of power is a question mark that looms over
7 the irrigation industry like a dark cloud. Rate increases
8 have caused reduction in irrigated acreage. Higher rates
9 will result in further reductions. But, worst of all,
10 the uncertainty of future power rates has all but assured
11 that irrigated agriculture is now a no-growth industry.
12 The only way to turn this around is to make electricity
13 available at a price irrigators can afford. This would
14 increase BPA and local utility sales and halt the decline
15 of this important industry. This would not only be a
16 boon to agriculture, but would be good for BPA and other
17 ratepayers.

18 In closing, I would note that Production
19 Credit Association records show that the number of farmers
20 going out of business for economic reasons increased two
21 and a-half times between 1979 and 1982. It's no coinci-
22 dence that these are the years BPA rates shot upward.

23 Unlike any time in recent history, irrigators
24 are literally fighting for their lives. BPA's Environmental
25 Impact Statement may say otherwise, but the real world .

1 is what it is. Unless BPA accepts the reality of the
2 irrigator's dilemma, we will not solve this growing regional
3 problem.

4 Thank you.

5 MR. HARLOW: Thank you, Mr. Galbreath.

6 Next, Mr. Byron Wagner.

7 MR. WAGNER: BPA staff, Director Ellis,
8 fellow participants in the rate hearing: My name is Byron
9 Wagner. I am an employee of Big Bend Electric Co-op,
10 which serves the rural areas of Adams and Franklin Counties.
11 However, I am here tonight to speak as an individual rate-
12 payer in support of a seasonal off-peak power rate for
13 irrigators because 70 percent of the power Big Bend distri-
14 butes is used for irrigation. This subject is of utmost
15 importance to our Cooperative.

16 Through June, Big Bend's sales were down
17 15 percent below 1982. How much of this decrease can
18 be attributed to higher rates is debatable. Obviously,
19 government farm programs and heavy rainfall has contributed
20 to this sharp reduction. However, a large percent can
21 be attributed to the power rate increase.

22 We have some irrigators who would have
23 irrigated or who would have turned on more pumps or who
24 would have irrigated longer if electric rates hadn't
25 increased so drastically, but other speakers have addressed

I. Irrigated Agriculture

Comment: Page II-36, paragraph 2. In explaining why irrigation has increased since 1950, it should be noted that low electric rates and active promotion by BPA, with promises of stable rates in the future, played a key role (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: Low electric rates were an important factor that encouraged irrigation development. This is acknowledged in the new text (Section IV.C.1).

During this period of rapid irrigation growth, BPA policy was guided in part by the Bonneville Project Act. Section 2(b) of this Act states that BPA was to "encourage the widest possible use of all electric energy." The combination of low and stable electricity prices certainly helped BPA to operate consistent with this policy.

Low and stable rates were possible because the hydro-based system was relatively inexpensive and was primarily a fixed-cost based system. Costs have risen rapidly since 1977, however, and rates have risen accordingly.

Comment: Page II-37, paragraph 3. The Draft EIS often distinguishes between sprinkler and gravity irrigation methods, but not between surface and deep well irrigation. Where water has to be lifted from deep wells, some exceeding 1,000 feet, the energy requirements become much greater. The EIS should give special attention to irrigators with high lifts as they represent a unique class which is greatly impacted by increased power rates (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: New text addresses this comment in Section IV.C. Also note that the model used to develop forecasts includes five irrigation lift zones as influencing variables. One lift zone covers deep well irrigators.

Comment: Page II-40, paragraph 1 In this section and others, the Draft EIS refers to BPA's increased power generation potential if irrigated acreage is reduced. It should be noted that there is presently no market for this power and that BPA is historically surplus during much of the irrigation season. In fact, the present irrigation load on BPA fits the natural river flows and complements BPA's generation and transmission system. It would be to BPA's advantage were the irrigation load to increase. Why are statements like ". . . any reduction in irrigation load combined with the increase in generation capability increases the proportion of that capability which can be used to serve nonirrigation load" often included in the EIS? They appear to have little relation to the real world problems associated with energy cost increases (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: The new text addresses BPA's forecasted surplus capability. However, BPA's summer load is only 8.3 percent less than the winter load and irrigation load is a significant contributor to summer peakload. April, the first month of heavy irrigation load, has the highest probability of producing a shortfall in generation capability below the level agreed to in the Pacific Northwest Coordination Agreement. See Section II.C. for a related discussion.

Comment: Page II-40, paragraph 3, etc. At this point the Draft EIS begins to paint a rosy picture for irrigated agriculture, noting that, "... no distinguishable differences in either total or new sprinkler irrigated acreage are projected to occur . . ." between rate levels 16.32 - 33.56 mills. The Draft EIS goes on to show, in Table II-8, how "Some new lands are brought under sprinkler irrigation regardless of the revenue level." It is further noted that, "By 2000, under those alternatives (including the proposed 1983 rate increase), the amount of dry land converted to sprinkler irrigation increases 100 percent."

These assumptions must be challenged in light of current trends. In recent years BPA wholesale rates have increased dramatically, causing increases at the retail level. During that period Big Bend Electric Cooperative has experienced a gradual decline in irrigation sales, plus a loss of some irrigation accounts. We can only believe that this trend will accelerate if power rates continue to climb. Other BPA preference customer utilities have seen greater irrigation load reductions.

It would be nice to be able to place confidence in the Draft EIS forecast of continued irrigation development despite increasing electric rates. However, those who live in a farm community where irrigation is the cornerstone of all agribusiness cannot overlook the changes that are currently taking place. Irrigators are already going out of business--in greater numbers than during the Great Depression. Deep well irrigators are particularly hard hit. Farm prices are depressed. Land that once sold for \$2,000 per acre is currently going unsold at \$1,000 per acre. It's a buyer's market for irrigated farms in BPA territory, especially if the water must be drawn from deep wells (Big Bend Electric Co-op, Ritzville, WA).

Comment: Page III-72, line 8. The Draft EIS paints a rosy picture for irrigated agriculture forecasting steady growth through the year 2000, with little consideration given to the current problems irrigators face. The report states, "BPA's proposed wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production." An irrigator disagrees with BPA's assessment. And a director of a rural electric co-op that has seen irrigation sales dwindle in recent years, challenges BPA's assessment (Gary Galbreath, Spokane Public Hearing).

Evaluation: New forecasts included in this statement show that each alternative will result in increased total irrigation and sprinkler irrigation compared to the 1980 base. Comparing projections in 1990 and 2000, projected impacts differ between revenue level alternatives except for the No Action and Proposal alternatives in 2000. The real price difference between these alternatives is only 1.3 mills per kilowatthour in 2000.

BPA recognizes that recent years have been difficult for agriculture. The cost of inputs has risen steadily and crop prices have declined in both real and nominal terms. Rising electricity prices certainly have played a part in the weakened cash-flow position of agriculture. It is quite likely that a number of individual irrigators will be unable to maintain profit margins sufficient to justify continued operation. Overall, however, it is believed that the industry as a whole will be capable of growth due to improved

agronomic techniques, increased product prices and improvements in irrigation technology including increased pump efficiencies and improved water distribution techniques.

Comment: Page III-72, paragraph 1. Recent evidence contradicts the statement, ". . . BPA's proposed wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production" Irrigated land is already going out of production and energy cost is one of the main factors (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: New text (Section II.B.3.f.) addresses comment.

Comment: Page III-72. The first paragraph includes the statement ". . . BPA's proposed wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production, as other farmers would purchase the land put up for sale by the marginal farmers." Further supportive data is needed for this statement. Without knowing the income-cost relationships assumed in the model, it is difficult to assess its validity.

Currently, some farmers pumping from deep wells and/or with high pump lifts from surface sources are in severe financial trouble, in part due to pumping power costs. Increased power costs are not going to make this situation better, and we think it is reasonable to believe that these costs, along with continued price increases in fertilizer, pesticides, machinery, etc., could bring about a financial situation which even superior management may not overcome.

The second paragraph on page III-72 points out that farmers are unable to pass along increases in production costs to consumers of their products. No doubt some of the increased power costs will be offset by advances in irrigation technology and management, but certainly not all. Unless prices received for farm products improve substantially, we believe farmers will be unwilling and/or financially unable, in the face of rising power costs, to convert dryland to sprinkler service at the rate shown in the statement for the proposed price alternative (U.S. Dept. of Interior, Washington, D.C.).

Evaluation: New text (Section II.B.3.f.) addresses comment.

Comment: Page III-73, line 2. The choice of words, "slightly depressed," is interesting. Is BPA aware of agriculture's place in the economy of the Northwest? As the Draft EIS seems to imply, one is looking at a slight erosion of irrigated agriculture if the worst case scenario takes place. The evidence speaks for itself and one will see a steep downward drop in irrigated acreage if BPA rates increase again--even slightly! The EIS seems out-of-touch with current events and is optimistic beyond all reason concerning the future of irrigated agriculture. It is hoped that the results of the linear programming model that is being developed by Northwest Economic Associates will relate better to the real world than the estimates presented in the Draft EIS (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: Forecasts from the model developed by Northwest Economic Associates did not address the near-term impact of alternative electricity prices. However, various supply and demand factors that may continue to

trouble agriculture in the near term are incorporated in the model. Some of these factors are discussed in Section II.B.3.f. Though the model did not project near-term adjustments to these factors, these adjustments are implicit in forecasts to the years 1990 and 2000. The model projects growth in total irrigated cropland acres and sprinkler irrigated cropland acres for all revenue level alternatives compared to the 1980 base.

Comment: Page IV-140, paragraph 2. This paragraph speaks to BPA's proposed changes in summer energy and demand rates which will benefit irrigators. These improvements are greatly needed and gratefully acknowledged. However, the EIS should consider the impacts of a separate irrigation rate as part of the Priority Firm rate. Because irrigation is a unique seasonal load that does match BPA's hydro resources, such a rate could be beneficial to the region. It should be considered in the final EIS (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: Evaluation of a special irrigation rate is included in section II.C. Furthermore, the current and proposed seasonal structures of BPA's rates accord irrigators benefits commensurate with the correspondence of their load shape to the supply curve of the hydroelectric system.

Comment: Page V-15, entire page. The response to the Draft EIS scoping comment was poorly conceived and did not speak to the real issues. The commentor had expressed concern at potential adverse impacts to utilities with a high percentage of irrigation loads. The Draft EIS comment that the low density discount ". . . may provide some revenue assistance through a lower priority firm rate . . ." is unreasonable in that the LDD does not take into account the fallout from WNP-4 and -5 or revenue shortfalls from decreasing irrigation sales. However, if this statement was included to imply that BPA is interested in considering expansion of the LDD to help remedy such problems rural utilities face, then Big Bend Electric Co-op is in 100 percent agreement (Big Bend Electric Co-op, Ritzville, WA).

Evaluation: The Draft statement as well as the new text discuss the potential adverse impacts to utilities with a high percentage of irrigation loads. It is apparent that utilities without a broad and diversified customer base would be less able to effectively compensate for reduced loads from a major customer class.

The respondent is correct that the Low Density Discount "does not take into account the fallout from WNP-4 and -5." The objective of the discount is quite clear and does not include mitigation of Supply System costs.

Comment: Pages II-36-48. It is difficult to assess the validity of the conclusions in the statement regarding the effects of alternative prices of electrical power on irrigated agriculture without knowing the prices paid for production inputs and prices received for crops which were used in the NADP model. It is difficult to accept the conclusion that the amount of sprinkler-irrigated land will increase by about 30 percent by the year 2000 for the proposed revenue level alternative. This is especially difficult to understand in view of the fact that this is the same level of development as is shown for the base rate and no action price alternatives (U.S. Dept. of Interior, Washington, D.C.).

Evaluation: New projections based on the NADP model are included in the text. An expanded discussion of methodology is also included in the new text. It is improbable, however, that model validation problems would be substantially reduced if crop and input prices used in the model were provided. The evaluator would still be lacking many other model inputs, assumptions, and constraints. It is not practical to provide a complete description of the model and its input in this document. However, data sources and the model design are available for inspection upon request.

Comment: Table II-8 on page II-44, indicates that a substantial amount of gravity service land will be converted to sprinkler service in spite of an increase in pumping power costs. It is difficult to understand the rationale for that prediction. Through the use of gated pipe systems, land that is gravity irrigated can obtain substantially improved labor and water efficiencies at half or less the investment cost of sprinklers and at a small fraction of the annual costs (U.S. Dept. of Interior, Washington, D.C.).

Evaluation: New text (Section II.B.3.f.) addresses comment.

Comment: Page II-36. The Draft EIS does not discuss the impacts of the rate alternatives on irrigated agriculture in California (The Resources Agency of California, Sacramento, CA).

Evaluation: Section II.B.3.c.(1). discusses the historic and projected importance of Pacific Northwest power sales to California. The California Energy Commission recently recommended that imports of surplus power to other regions should be considered a preferred power resource. BPA's proposed rates are still considerably lower than average operating costs of generating facilities in California. Solely from a price perspective, it is to California's advantage to purchase power that is surplus to the Pacific Northwest. However, it is apparent that, all other conditions unchanging, any revenue level alternative that results in increased nonfirm and surplus firm power rates will have an increasing effect on electric rates to California consumers. With respect to relative impacts to various customer classes in California, irrigated agriculture customers may be affected less than many other classes. California agriculture receives a relatively large share of water from Federal and local water projects, so water charges that reflect the impact of energy price increases probably will increase at a relatively slow rate because of the institutional nature of the Federal water market and because local water projects require little pumping and thus use less energy (California Department of Water Resources, 1982, Outlook for Water Consumption by California's Feed and Forage Industry Through 2010, Bulletin 212, February, p. 60).

II. Direct Services Industrial Customers

Comment: Page IV-36/line 24: Replace the word "reduced" with "eliminated." (Direct Service Industries, Inc.)

Evaluation: BPA disagrees with this change. Our analysis shows that BPA's rate increases have reduced the price advantage of Pacific Northwest aluminum producers as compared to other regions of the country, but not eliminated it entirely (see Table IV-8).

Comment: Page II-18/line 3. "13" should be "is"; p. IV-26 Figure IV-1: lines pointing to plants #13-17 are not very accurate; p. IV-27/line 22: "11 existing aluminum plant" should read "10 existing aluminum reduction plants"; p. IV-29/Table IV-3: line 1 col. C: insert comma after "Primary Aluminum;" line 11, Col. C: change to read "Primary Aluminum, Rod, Wire, & Cable;" line 14, Col. C: change to read "Magnesium & Ferrosilicon;" p. IV-32/line 3: change as follows: "Nonfirm energy is offered to Northwest preference customers before it is used to serve DSI loads during the pendency of the U.S. Supreme Court consideration of the Ninth Circuit Court decision in Central Lincoln I.; p. IV-32, Line 18: change to read: ". . . DSIs have borrowed on their firm energy as previously discussed, subsequent stream flows don't restore the reservoirs and the energy is needed by BPA to meet its firm obligations;" p. IV-34/line 13: change the word "deficients" to deficits;" p. IV-37/Line 9: "special emphasis is focused on the 10 aluminum smelters BPA serves;" p. IV-57/line 16: insert "non aluminum" before "DSIs;" (Direct Service Industrial Customers, Inc.)

Evaluation: Text has been corrected.

Comment: Page II-8, line 10. As the Pacific Northwest Utilities Conference Committee (PNUCC) has indicated in its comments on BPA's Environmental Assessment for the Water Budget, it is believed that the Water Budget will result in more than a 1 mill/kWh increase in the Priority Firm rate. It also may adversely affect "combination service" for the DSI top quartile loads (Direct Service Industries, Inc., Portland, OR).

Evaluation: PNUCC said in its comments on BPA's Environmental Assessment for the Water Budget that BPA did not account for the costs of new resources that would be acquired to replace the lost Firm Energy Load Carrying Capability (FELCC). No decision has been made by BPA as to how or when those resources will be replaced. As long as there is a surplus of power, there will probably be no replacement of the FELCC used by the Water Budget. When there is a replacement, it is not known if the resources will be in the FBS, Exchange or New resource pool. Whether the Water Budget will adversely affect the "combination service" for the DSI top quartile is speculative. In surplus periods, there is sufficient FELCC to shift and surplus firm power to service the top quartile. In the longer term, providing for the Water Budget may affect the resource combination used to serve the top quartile, subject to contract restrictions; but it is not clear that there would be a change in cost. Also note that the estimate of the impact of providing for the Water Budget on the Priority Firm rate is decreased from 1 mill/kWh to .05 mills kWh. This reduction is the result of correcting a modeling error in the draft document.

Comment: Pages IV-54-58. The forecasts of DSI loads produced by BPA's simulation model are too high. This may result largely from BPA's optimistic outlook on improvements in the aluminum market. If DSI power costs continue in the upper 25 to 40 percent of the work power costs, the operating levels BPA predicts are unlikely to be attained (Direct Service Industries, Inc., Portland, OR).

Evaluation: The forecast was based on the best available information at the time. The forecasts of DSI loads will be revised for final ratemaking purposes to reflect the most current production cost data inputs and changes

to the forecast of aluminum price. The forecast of DSI loads for the final rates will also reflect any other information or policy changes which become appropriate as a result of the rates hearing process.

III. Southwest Customers

Comment: Page IV-142. Inasmuch as mitigation measures were not identified, the discussion of unavoidable adverse impacts should include out-of-state impacts (The Resource Agency of California, Sacramento, CA).

Evaluation: Text (Section IV.K.) has been modified to address this concern.

Comment: Page IV-131. BPA considers conservation measures costing less than 35 mills per kilowatthour as cost-effective, apparently based on the LRIC analysis. The Draft EIS should recognize that higher levels of conservation will be cost-effective if the power conserved can be sold out-of-state at a price higher than the cost of conservation (The Resource Agency of California, Sacramento, CA).

Evaluation: The text no longer refers to 35 mills per kilowatthour. The 35 mills calculation for cost-effectiveness is subject to recalculation. BPA agrees that higher levels of conservation could be cost-effective if the power conserved can be sold out of the region at a higher price than the cost of the conservation.

Comment: Page II-25. The DEIS notes that, "impacts of BPA revenue increases on the retail rates of Pacific Southwest utilities were addressed in the Final Environmental Impact Statement, 1979 Wholesale Rate Increase." There is no explanation why the impacts of the 1983 rate increase would be the same as those of the 1979 rate increase. (The Resources Agency of California, Sacramento, CA).

Evaluation: A new section (II.B.3.c.(1)) on the impact of BPA revenue level increases on the Pacific Southwest has been added for this Final EIS.

Comment: Page II-14. The analysis of effects on demand for electricity covers only regional (Northwest) demand. Under the LRIC pricing alternative, more electricity would be available for export, so that total demand (including export areas) would decline less than shown here, possibly remaining the same (The Resources Agency of California, Sacramento, CA).

Evaluation: The amount of power available for export in 1990 and 2000 will be a function of the balance between Pacific Northwest loads and resources. The LRIC alternative would make more electricity available for export only to the extent that BPA and other Northwest utilities plan for and acquire resources to satisfy Northwest loads that fail to develop. Neither BPA nor other Northwest utilities plan to build generation resources in the Northwest for the purpose of exporting power outside the region, regardless of the existence of such demand. As discussed in Section II.B.3.c.(1), purchases by California of surplus BPA energy and capacity will depend on price and the availability of substitute sources of power.

Comment: Pages II-29-30. This discussion of effects on low-income consumers applies only to Pacific Northwest consumers. If the LRIC were below the incremental costs of California utilities' supplies, the LRIC alternative could reduce retail rates for low-income and other California consumers (The Resources Agency of California, Sacramento, CA).

Evaluation: Any power purchased by California at BPA's LRIC or any other price lower than the existing statewide average power cost would lower California's average power cost. A portion of the power cost savings would probably be passed in part to low income consumers. A smaller savings would be expected under the LRIC alternative than under the other alternatives under examination.

Comment: Pages II-62-63. The "projected environmental impacts of implementation of proposed rates" apply only to the Northwest. There should be some discussion of the out-of-state impacts of not only those rates which apply to the out-of-state users but also the increased or decreased availability of surplus power (The Resources Agency of California, Sacramento, CA).

Evaluation: This comment is addressed in the new text (Sections II.B.3.c.(1) and IV.F.) as well as in evaluations of other comments in this section.

Comment: Page II-102. The DEIS correctly notes that, "purchasers could use surplus firm power to shut down high-cost oil or other thermal generation, or could delay completion of other generation now under construction. This could reduce overall power costs to purchasing utilities, thereby reducing retail rates." However, the noted impact is that of the surplus firm power rate itself, not of the proposed changes. It is not clear what the impact of the proposed changes on California utilities or retail consumers would be (The Resources Agency of California, Sacramento, CA).

Evaluation: Comment is addressed in the new text (Section II.B.3.c.(1)).

Comment: Pages II-109-115. Again, the DEIS does not state the impacts of the revised nonfirm energy rate schedules on consumers outside of the region (The Resources Agency of California, Sacramento, CA).

Evaluation: Comment is addressed in the new text (Sections II.B.3.c.(1) and II.C.3.c.).

Comment: Pages IV-3-4. This discussion of "BPA's Load and Resource Modeling Processes" does not mention energy supply and demand in the areas to which BPA power is exported (The Resources Agency of California, Sacramento, CA).

Evaluation: BPA does not plan for or acquire resources to serve an export market. Therefore, it is unnecessary to forecast energy supply and demand in areas to which BPA exports power. A general treatment of this subject appears in Section IV.F.

Comment: Page IV-15. The Draft EIS states that the least cost resource mix model, "gives only limited treatment to the seasonality of loads and resource output and to better than critical hydro-conditions." Use of the model could understate seasonal energy surpluses and shortages and, hence, understate the benefits of sales to and purchases from utilities in other regions (The Resources Agency of California, Sacramento, CA).

Evaluation: Comment is addressed in new text (Section IV.B.3.).

Comment: Page IV-56. The Draft EIS indicates a sudden reduction in DSI loads if the long-run incremental cost pricing alternative were adopted. This implies severe local socioeconomic impacts could occur. However, the analysis assumes a sudden jump of rates from 27.5 mills per kilowatthour to 42.6 mills per kilowatthour. A more realistic LRIC alternative would assume a gradual increase in rates which could mitigate the local socioeconomic impacts (The Resources Agency of California, Sacramento, CA).

Evaluation: With respect to BPA's analysis of revenue level impacts to the DSI's, the impacts resulting from a DSI rate which falls somewhere between the rate levels assumed for the proposed and LRIC alternatives would be bounded by the projected impacts under those two alternatives. For the Final EIS, BPA did include a direct financing alternative which assumed that BPA would finance completion of WNP-2 and continued construction of WNP-3 from rates. However, this alternative did not involve an assumed increase in the Industrial Firm Power rate, since the increased costs associated with this alternative would be reflected in the rates to other customer classes. Although BPA did not model an additional DSI rate level for the Final EIS, other discussions are included pertaining to classification and rate design alternatives resulting in higher DSI rate levels (Sections II.C.1.b. and II.C.1.h.).

IV. Miscellaneous

Comment: The actual proposed rate changes were not readily apparent. It is suggested that, for the benefit of the lay citizen who may review this document, BPA provide the information on existing rate schedules and proposed changes (particularly on pp. II-59-118) in tabular form to accompany the discussion in the text (U.S. Environmental Protection Agency, Seattle, WA).

Evaluation: A new section (II.C.2.) on BPA's Wholesale Power Rate Initial Proposal has been added to Chapter II.

Comment: Page III-26. Under a listing of State Parks in Oregon, the Cascadia, Deschutes River, and Hot Rock are State Parks. Crater Lake National Park is not in Douglas County, rather it is in Klamath County. It is unclear as to intent of providing Table III-5. If it is just to give examples of those types of natural features, the table is adequate. If it is to address all known significant natural features and major recreation areas, it falls short. The Columbia River Gorge, which is near several DSI plants, contains a number of State Parks and U.S. Forest sites which have extreme natural and aesthetic values (Cook, Oregon Parks and Recreation).

Evaluation: Table III-5 has been removed and the text has been modified to address the expressed concern.

Comment: BPA has not addressed the potential environmental impacts of the proposed elimination of the Spill rate. BPA must fully address this issue. (Los Angeles Department of Water & Power, Los Angeles, CA.)

Evaluation: Analysis of elimination of the Spill rate has been added (Sections II.C.3.c. and IV.I.2.o.).

Comment: BPA has not addressed the potential environmental impacts of the proposed transmission rates in the Draft EIS. BPA must fully address this issue (Los Angeles Dept. of Water & Power, Los Angeles, CA).

Comment: BPA has not addressed the potential environmental impacts of the transmission access adder (Los Angeles Dept of Water & Power, Los Angeles, CA).

Evaluation: The subject of this EIS is the wholesale power rates. The transmission rates, including the access adder, are the subject of a separate environmental review.

Comment: Page II-13. The summary of the impacts of alternative revenue levels excludes socioeconomic impacts not directly related to rates. For example, the construction and operation of power plants will require expenditures for local public services such as schools and roads (The Resources Agency of California, Sacramento, CA).

Evaluation: The summary of impacts of alternative revenue levels focused on primary impacts. A paragraph acknowledging the secondary impacts such as schools and roads, has been added (Section II.B.3.).

Comment: Page IV-59, line 26. The sentence refers to small hydroelectric as a potential resource to meet regional generation needs. Adding units to existing hydroelectric projects does not fit into the "small hydroelectric" definition as discussed on pages IV-65, 66, 67 of 147. We suggest either the reference to small be deleted or an additional discussion be added for hydroelectric projects larger than 15 MW (Dept. of the Army, Portland, OR).

Evaluation: The text (Section IV.H.3.) has been modified to address the comment.

Comment: Page II-75, lines 12-16. The conclusion that combustion turbines will most likely supply additional peaking needs is premature. The Corps of Engineers, Bureau of Reclamation, and Mid-Columbia PUD's have and are studying adding peaking units to existing hydroelectric projects. When the need for peaking capacity approaches, adding units to existing hydro projects will be compared with combustion turbines. Then the decision can be made based on economics (Dept. of the Army, Portland, OR).

Evaluation: The cited text no longer addresses the issue. Please refer to Section II.B.3.g.

Comment: Section III-B. This section discusses several factors which would adversely affect fish and wildlife resources. These factors are directly applicable to wholesale power rate adjustments which would alter demand for power, thus affecting operation of the Columbia River dams. The resultant changes in river operations would in turn influence flows and water quality directly affecting fish and wildlife resources (e.g., increased turbine mortality and nitrogen poisoning of juvenile salmonids). However, under Environmental Consequences, Chapter IV, there is no discussion describing what effects each alternative would have on fish and wildlife resources. Therefore, the final EIS should present information describing the potential adverse impacts on fish and wildlife resources for each alternative (U.S. Dept. of Interior, Washington, D.C.).

Evaluation: It is not expected that there will be any significant difference in river operations between the revenue level alternatives. The hydroelectric facilities will be used to the maximum potential regardless of the alternative. The choice of alternative, however, could affect the use of thermal facilities. No significant difference between the alternatives is expected as to the impact on fish and wildlife.

Comment: Pages III-28-36. Burning of wood for home heating is identified as one of the two major activities being undertaken by consumers to reduce power costs. Table II-4 (on page II-16) does not reflect this activity. Since wood burning is cited (page III-33, first sentence) as a major source of air pollution in the region, the statement should contain an estimate of the effect of alternative electrical rates on the burning of wood for space heating (U.S. Dept. of Interior, Washington, D.C.).

Evaluation: BPA agrees that in forecasting residential consumption, wood needs to be considered as a fuel choice for space heating. The framework exists in BPA's residential model to incorporate wood space heating. However, data are scarce on the level of consumption, the sources of wood, the continued availability and use of wood, and the reasons behind choosing wood for space heating. BPA is currently conducting a Pacific Northwest Residential Energy Consumption Survey (data will be available in February 1984). This regional survey will provide a sub-sample of wood-consumers that can be surveyed with follow-up mail questionnaires and telephone interviews to obtain more detailed information concerning its usage. This wood survey is crucial because there are no secondary sources of data concerning wood consumption. In spite of the current lack of definitive data, this statement does recognize the environmental impact of wood burning on the region.

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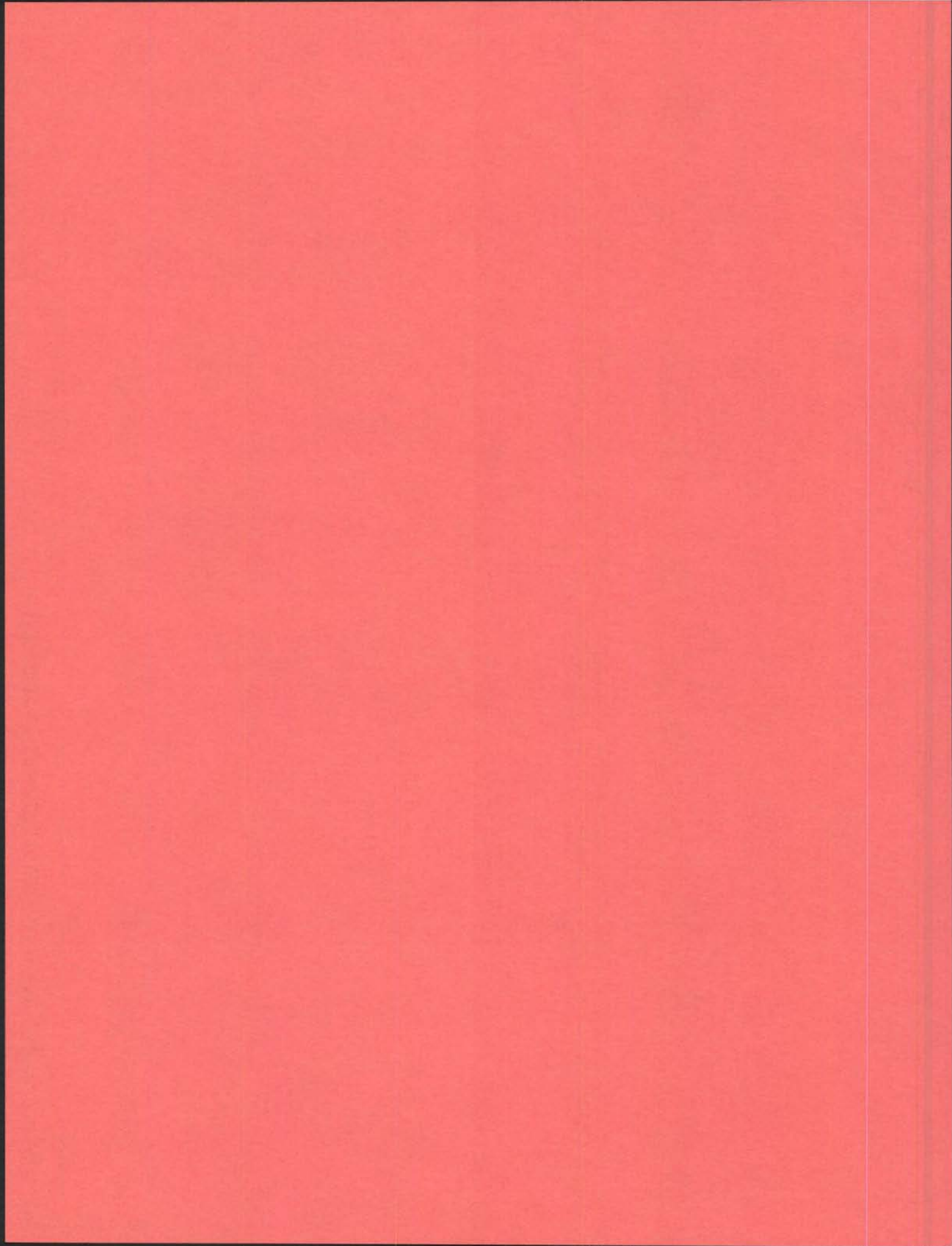
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Chapter VII

List of Preparers



VII. List of Preparers of the Environmental Impact Statement

Project Director

Taves, John M.

Chief, Retail Rates and Environmental Studies Section - Wholesale Rates Branch

Educational background: B.A. - 1968 - Psychology; M.A. - 1971 - Social
Psychology; Ph.D. - 1975 - Sociology

Experience: Research and teaching (1972-1976); work on environmental and
rate design projects with BPA (1976-present).

Managing Editor

Palmatier, Sheryl E.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.A. - 1964 - Economics; M.S. - 1977 - Resource
Economics

Experience: Social worker (1964-1970); Research Assistant for fisheries,
recreation, and resource planning (1974-1977); Economist,
Federal Energy Regulatory Commission (1977-1978); Economist,
Conservation and Renewable Resources, Department of Energy
(1978-1982); Economist/Public Utilities Specialist, BPA
(1981-present).

Major Authors

Blumhardt, Orville J.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.S. - 1974 - Business Economics; M.S. - 1977 -
Agricultural Economics

Experience: Six years experience including market research, use of
econometric models, forecasting, and use of data processing;
marginal cost studies and environmental analysis with BPA
(1981-present).

Boling, Rodney E.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.A. - 1967 - Economics and Business; M.A. - 1978 -
Agricultural Economics

Experience: Research Associate involved in evaluating irrigated agriculture
response to alternative electricity prices (1978); land use
planning, land price/development modeling and analysis, land use
inventories, and work on economic and land use components of a
transportation draft environmental impact statement (1978-1981);
BPA Division of Rates (1981-present).

Filip, Patricia A.

Writer/Editor - Wholesale Rates Branch

Educational background: B.A. - 1971 - English; M.A. - 1972 - Journalism

Experience: Writing and editing with newspapers and private industry
(1972-1978); work on environmental and rate development
documents for BPA (1978-present).

Montgomery, Douglas G.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.A. - 1964 - Government; M.P.A. - 1966 - Public Administration/Urban Studies; Ph.D. - 1969 - Social Science (Economics and Political Science)

Experience: Policy Analyst with Economic Development Administration, Department of Commerce (1969-1970). Full-time faculty member: Cornell University (1968-69); Case Western Reserve University (1970-1974); Lake Forest College (1974-1975); Portland State University (1975-1982). Principal investigator on five Federally funded gerontological and organizational research studies. BPA retail rate, environmental, organizational, and billing credit studies (1982-present).

Technical Support Staff

Armstrong, David J.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.A. - 1977 - Economics; M.A. - 1979 - Economics

Experience: Residential energy demand forecasting for BPA Division of Power Requirements (1980-1982); rate forecasting for BPA Division of Rates (1982-present).

Holmstrom, John C.

Energy Resource Specialist - Division of Power Resources

Educational background: B.S. - 1964 - Mathematics; Ph.D. - 1972 - Regional Planning

Experience: Professor, Urban and Regional Planning, University of Hawaii (1970-81); BPA Energy Resource Specialist (1981-present).

Houchen, Loren J.

Public Utilities Specialist - Wholesale Rates Branch

Educational background: B.A. - 1977 - Economics and French

Experience: Electricity pricing and demand models for environmental documents (1979-present).

McConnaughey, John S.

Chief - Energy Analysis Section, Division of Power Requirements

Educational background: B.A. - 1962 - History; M.A. - 1975 - Economics; Ph.D. - 1976 - Economics

Experience: Research on lifecycle costing, energy conservation, building economics, and economics of regulation for the National Bureau of Standards (1976-79); end use and econometric forecasting and analysis for BPA (1979-present).

Spies, Paul A.

Industry Economist - Division of Power Requirements

Educational background: B.S. - 1975 - Biology; M.S. - 1979 - Resource Economics

Experience: Economic analysis of industries for BPA (1980-present).

Wilkins, John R.

Agricultural Economist - Division of Power Requirements

Educational background: B.S. - 1960 - Agricultural Economics; M.S. - 1968 - Agricultural Economics; Ph.D. - 1979 - Resource Geography

Experience: River basin planning and economics for U.S. Department of Agriculture (1968-1977); irrigation, food processing, and related water planning and economic forecasting for BPA (1977-present).

Editorial Reviewers

Buchanan, Shepard C.

Industry Economist - Office of Power and Resources Management

Educational background: B.S. - 1976 - Resource Economics; M.S. - 1979 - Resource Economics

Experience: Forest Economist for U.S. Forest Service (1980-1982); environmental cost analysis for BPA (1982-present).

Burbach, L. Linda

Management Assistant - Environmental Manager's Office

Experience: Processing environmental documents with BPA's Environmental Manager's office (1980 - present).

Carr, John D.

Chief, Wholesale Rates Branch

Educational Background: M.S. - 1975 - Mathematics; M.A. - 1977 - Economics

Experience: Wholesale Rates Branch with BPA since 1978.

Foulkes, Gabrielle F.

Environmental Specialist - Office of Power and Resources Management

Educational background: B.A. - 1977 - Education

Experience: Portland Bureau of Planning (1977-1978); Corps of Engineers (1978); work on environmental documents for BPA (1978-present).

Harper, Richard J.

Fishery Biologist - Division of Fish and Wildlife

Educational background: B.S. - 1975 - Experimental Biology; M.S. - 1982 - Natural Resources (fisheries)

Experience: Great Lake Fishery Laboratory (1976-1977); Fisheries Assistance Office - Vancouver (1977-1979); National Fisheries Research Center (1979-1981); BPA (1981-1983)

McKinney, Thomas C.

Senior Environmental Specialist - Environmental Manager's Office

Educational background: B.A. - 1976 - Geography

Experience: Developing policies and procedures and providing assistance enabling BPA to comply with environmental regulations.

Pyrch, John B.

Environmental Coordinator - Office of Power and Resources Management

Educational background B.A. - 1968 - Geography; M.S. - 1973 - Geography

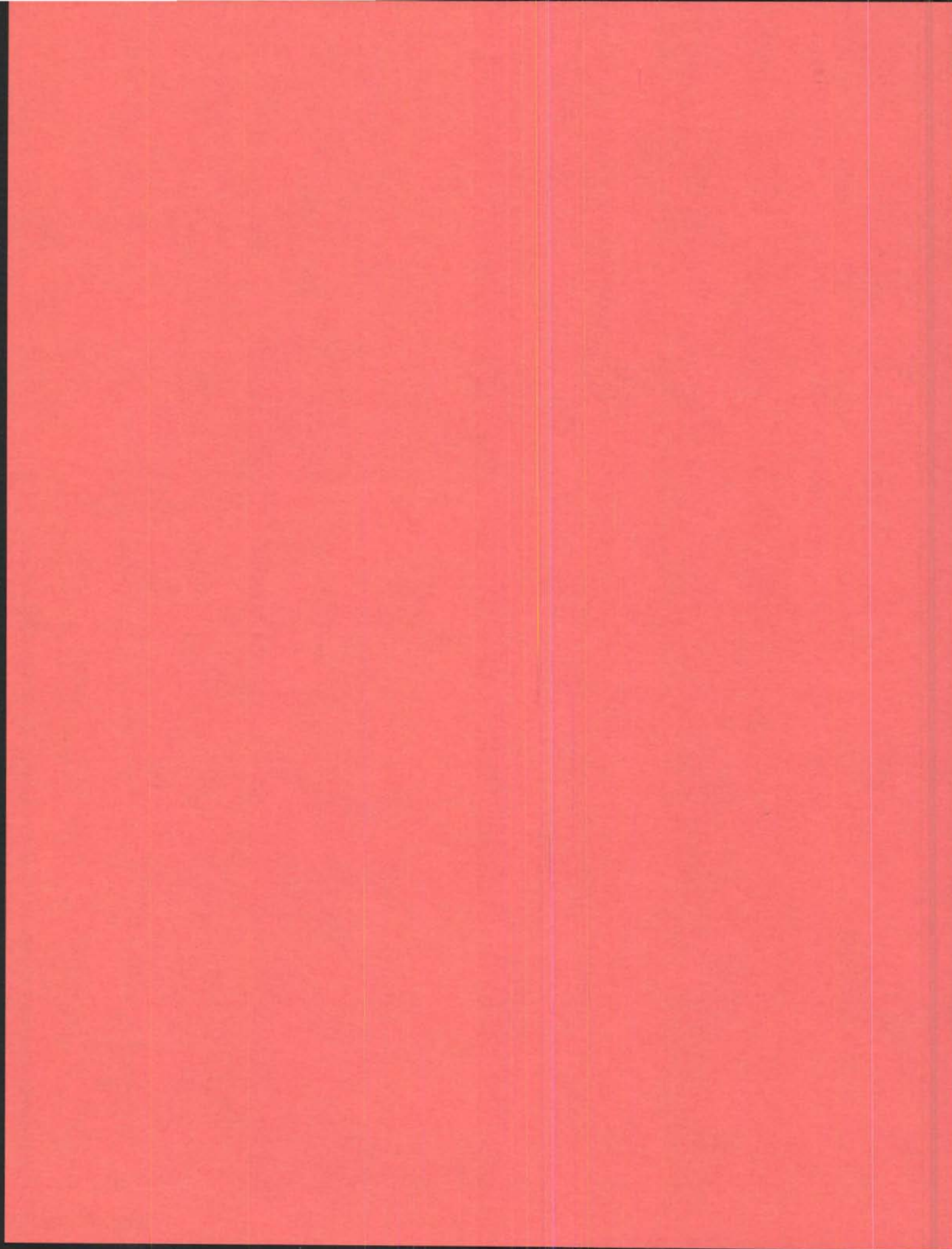
Experience: Work on environmental procedures and project impact evaluations for BPA (1975-present); lecturer (part-time), Portland State University (1978-present).

Special Support Staff

Barbara Aston, Linda Drake, Maria Dunn, Debra Hansen, Merle Horn, Lanai Jeche, Betty Lentz, Linda McDonald, Barbara Shafer, Marilyn Watson, Connie Whitlow, and Annette Younger.

Chapter VIII

List of Persons Receiving the EIS



STATE of CALIFORNIA

CITY/COUNTY/STATE GOVERNMENT

Board of County Commissioners, County of Modoc, Alturas
Board of County Supervisors, County of Lassen, Susanville
California Association of Counties, Sacramento
California Energy Commission, General Counsel, Sacramento
California Public Utilities Commission, San Francisco
California State Clearinghouse, Sacramento
Department of Housing and Community Development, Sacramento
Department of Water Resources, Sacramento
Governor of the State of California, Sacramento
Office of Planning and Research, Sacramento
State Historic Preservation Office, Sacramento
The Resources Agency of California, Sacramento

FEDERAL AGENCIES

U.S. Department of the Interior

Geological Survey, Menlo Park
Interagency Archeological Service, San Francisco

U.S. Department of Energy

Federal Energy Regulatory Commission, San Francisco

INTEREST GROUPS

Bendix Environmental Research, Inc, San Francisco
Edward Aderkas, Sacramento
Edward Fitzgerald Dibble, Redlands
Natural Resource Defense Council, San Francisco
Potlatch Corporation, San Francisco

CUSTOMERS

Alumax Incorp, San Mateo
City of Burbank, Burbank
City of Glendale, Glendale
City of Los Angeles, Los Angeles
City of Pasadena, Pasadena
CP National, Concord
Kaiser Aluminum & Chemical Corp, Oakland
Pacific Gas & Electric Co, San Francisco
Sacramento Municipal Utility District, Sacramento
San Diego Gas & Electric Co, San Diego
Southern California Edison Co, Rosemead
Surprise Valley Electric Coop, Alturas
US Dept of the Navy, Naval Facilities Engineering Command, San Bruno

^{1/} In addition to mailing the EIS to persons on this list, we are sending a letter announcing availability of the draft EIS to a large number of persons who have shown an interest in BPA's rate process. Persons who receive the letter may obtain a copy of the EIS from BPA if they wish.

STATE of COLORADO

FEDERAL AGENCIES

Boards, Committees, and Commissions

Advisory Council on Historic Preservation, Golden

U.S. Department of the Interior

Bureau of Land Management, Denver

U.S. Department of Energy

Western Area Power Administration, Fort Collins, Golden, & Loveland

INTEREST GROUPS

Black Hawk Associates, Denver

Environmental Defense Fund, Denver

The Wilderness Society, Western Regional Office, Denver

STATE of IDAHO

CITY/COUNTY/STATE GOVERNMENT

A-95 Coordinator, East Central Idaho Planning and Development Assn, Rexburg

A-95 Coordinator, Idaho State Clearinghouse, Boise

Ada Planning Association, Executive Director, Boise

Association of Idaho Cities, Boise

Boise Energy Task Force, Boise

Board of County Commissioners

County of:

Ada, Boise

Bannock, Pocatello

Bear Lake, Paris

Benewah, St. Maries

Bingham, Blackfoot

Blaine, Hailey

Boise, Idaho City

Bonner, Sandpoint

Bonneville, Idaho Falls

Boundary, Bonners Ferry

Butte, Arco

Camas, Fairfield

Caribou, Soda Springs

Cassia, Burley

Clark, Dubois

Clearwater, Orofino

Custer, Challis

Elmore, Mountain Home

Franklin, Preston

Fremont, St. Anthony

Gem, Emmett

Gooding, Gooding
Idaho, Grangeville
Jefferson, Rigby
Jerome, Jerome
Kootenai, Couer d'Alene
Latan, Moscow
Lemhi, Salmon
Lewis, Nez Perce
Lincoln, Shoshone
Madison, Rexburg
Minidoka, Rupert
Nez Perce, Lewiston
Oneida, Stone
Owyhee, Murphy
Payette, Payette
Power, American Falls
Twin Falls, Twin Falls
Shoshone, Wallace
Teton, Briggs
Valley, Cascade
Washington, Weiser

City of Albion
City of Blackfoot
City of Boise
City of Bonners Ferry
City of Burley
City of Caldwell
City of Coeur d'Alene
City of Declo
City of Heyburn
City of Idaho Falls
City of Lewiston
City of Minidoka
City of Moscow
City of Mountain Home
City of Nampa
City of Payette
City of Pocatello
City of Rexburg
City of Rupert
City of Stanley
City of Twin Falls

Clearwater Economic Development Association, Moscow
Division of Economic and Community Affairs, Boise
Governor of the State of Idaho
Idaho Association of Counties, Boise
Idaho Dept. of Agriculture, Boise
Idaho Oregon Regional Planning and Development Association, Weiser
Idaho Public Utilities Commission, Boise
Idaho State Historical Society, Boise
NW Power Planning Council:
 W. Larry Mills, Boise
 Robert W. Saxvik, Boise

Office of the Attorney General, Boise
Panhandle Area Council, Coeur d'Alene
Region IV Development Association, Inc, A-95 Coordinator, Twin Falls
State Energy Committee, Idaho House of Representatives, Boise
State Energy Committee, Idaho Senate, Boise
State of Idaho, Department of Water Resources, Boise
State of Idaho, Office of Energy, Boise
State Planning and Community Affairs, Boise
Southeast Idaho Council of Governments, Judy L. Harmon, Pocatello
Southwest Idaho Council of Governments, Renee Youree, Pocatello

FEDERAL AGENCIES

U.S. Department of Agriculture
Research Service, Kimberly

U.S. Department of the Interior
Bureau of Indian Affairs, Northern Idaho Agency, Lapwai
Bureau of Land Management, Coeur d'Alene
Bureau of Reclamation, Pacific Northwest Region
Regional Director, Boise
U.S. Fish and Wildlife Service, Boise

INTEREST GROUPS

Larry Crowley, Boise
Power Engineers, Hailey
P. F. Randall, Idaho Falls

LIBRARIES

Boise Public Library, Reference Department, Boise
Boise State University Library, Boise
College of Idaho, Terteling Library, Caldwell
Idaho State Library, Boise
Idaho State University Library, Documents Division, Pocatello
Ricks College, David O. McKay Library, Rexburg
University of Idaho Library U.S. Documents, Moscow

INDIAN TRIBES

Nez Perce Tribe of Idaho, Lapwai

INTEREST GROUPS

CEDA, Moscow
Committee for Fair Rates, Coeur d'Alene
Common Cause, State Director, Challis & Coeur d'Alene
Energy and Mass Environment, Caldwell
Idaho Citizens Coalition, Boise
Idaho Conservation League, Boise
Idaho Consumer Affairs, Nampa
Idaho Environmental Council, Idaho Falls & Moscow
Kootenai Environmental Alliance, Coeur d'Alene
League of Women Voters of Idaho, Pocatello

Ratepayers, Bonners Ferry
Sierra Club, Middle Snake Group, Boise

CUSTOMERS

CH2M Hill, Boise
City of Bonners Ferry, Bonners Ferry
City of Burley, Burley
City of Heyburn, Heyburn
City of Idaho Falls, Idaho Falls
City of Rupert, Rupert
Clearwater Power Co, Lewiston
Fall River Rural Electric Coop Inc, Ashton
Farmers Electric Co, Rupert
Idaho Light and Power Coop Assn Inc, Grangeville
Idaho Power Co, Boise
Kootenai Electric Coop, Hayden Lake
Lost River Electric Coop Inc, Mackay
Northern Lights Inc, Sandpoint
Prairie Power Coop Inc, Fairfield
Raft River Rural Electric Coop, Malta
Riverside Electric Co, Rupert
Rural Electric Co, Rupert
Salmon River Electric, Challis
South Side Electric Lines Inc, Declo
Southend Mutual Electric Co Limited, Rupert
Unity Light and Power Co, Burley

STATE of MONTANA

CITY/COUNTY/STATE GOVERNMENT

Butte Silver Bow Government, Energy Office, Butte
Board of County Commissioners

County of:

Beaverhead, Dillon
Broadwater, Townsend
Deer Lodge, Anaconda
Flathead, Kalispell
Gallatin, Bozeman
Glacier, Cut Bank
Granite, Philipsburg
Jefferson, Boulder
Lake, Polson
Lewis & Clark, Helena
Lincoln, Libby
Madison, Virginia City
Meagher, White Sulphur Springs
Mineral, Superior
Missoula, Missoula
Pondera, Conrad

Powell, Deer Lodge
Ravalli, Hamilton
Sanders, Thompson Falls
Silver Bow, Butte
Teton, Choteau
City of Anaconda
City of Bozeman
City of Butte
City of Dillon
City of Helena
City of Kalispell
City of Missoula
Department of Commerce, Helena
Department of Community Affairs, Helena
Department of Natural Resources and Conservation, Helena
Governor of the State of Montana, Helena
Montana Association of Counties, Helena
Montana League of Cities and Towns, Helena
Montana Public Utilities Commission, Helena
Montana State Clearinghouse, Budget & Program Planning, Helena
Montana State Energy Office, Helena
Northwest Power Planning Council, Helena
Research & Information Systems, Department of Community Affairs, Helena
State Energy Committee, Montana House of Representatives, Helena
State Energy Committee, Montana Senate, Helena
State Historic Preservation Office, Montana Historical Society, Helena

FEDERAL AGENCIES

U.S. Department of Agriculture

Forest Service, Region 1, Missoula
Soil and Conservation Service, Kalispell

U.S. Department of Energy

Western Area Power Administration, Billings

U.S. Department of the Interior

Bureau of Indian Affairs, Flathead Irrigation Project, Polson
Bureau of Land Management, Montana State Office, Billings
Bureau of Reclamation, Upper Missouri Region, Billings

LIBRARIES

Montana State University Library, Documents Library, Bozeman
University of Montana, Documents Division, Missoula
University of Montana, Environmental Library, Missoula

INTEREST GROUPS

Common Cause, State Director, Missoula
Energy Extension Service, Helena
Environmental Information Center, Helena
Environmental Quality Control, Helena
Flathead Citizens for Safe Energy, Whitefish

Flathead Environmental Report, Kalispell
Charles Galloway, Anaconda
League of Women Voters, Missoula
Montana Consumer Counsel, Helena
Sierra Club, Missoula
Western Environmental Trade Association, Columbia Falls

CUSTOMERS

Arco Metals Co, Columbia Falls
Flathead Electric Coop Inc, Kalispell
Flathead Irrigation Project, St Ignatious
Glacier Electric Coop Inc, Cut Bank
Lincoln Electric Coop, Eureka
Missoula Electric Coop Inc, Missoula
Montana Power Co, Butte
Ravalli County Electric Coop Inc, Corvallis
Stauffer Chemical Co, Butte
Vigilante Electric Coop Inc, Dillon

INDIAN TRIBES

Confederated Salish and Kootenai Tribes of the Flathead Reservation, Pablo

STATE of NEVADA

CITY/COUNTY/STATE GOVERNMENT

Board of County Commissioners:

County of:

Elko, Elko

Humboldt, Winnemucca

City of Elko, Office of The Mayor

Colorado River Commission, Las Vegas

Governor of the State of Nevada, Carson City

Nevada League of Cities, Carson City

Office of the Governor, State Planning Coordinator, Carson City

Public Utilities Commission, State of Nevada

State Historic Preservation Officer, Carson City

FEDERAL AGENCY

U.S. Department of Energy

Western Area Power Administration, Boulder City

CUSTOMER

Wells Rural Electric Co, Wells

STATE of OREGON

CITY/COUNTY/STATE GOVERNMENT

Blue Mountain Intergovernmental Council, Enterprise
Board of County Commissioners

County of:

Baker, Baker
Benton, Corvallis
Clackamas, Oregon City
Clatsop, Astoria
Columbia, St. Helens
Coos, Coquille
Crook, Prineville
Curry, Gold Beach
Deschutes, Bend
Douglas, Roseburg
Gilliam, Condon
Grant, Canyon City
Harney, Burns
Hood River, Hood River
Jackson, Medford
Jefferson, Madras
Josephine, Grants Pass
Klamath, Klamath Falls
Lane, Eugene
Lincoln, Newport
Maine, Vale
Marion, Salem
Multnomah, Portland
Polk, Dallas
Sherman, Moro
Tillamook, Tillamook
Umatilla, Pendleton
Union, La Grande
Wallowa, Enterprise
Wasco, The Dalles
Washington, Hillsboro
Wheeler, Fossil
Yamhill, McMinnville

Central Oregon Intergovernmental Council, Redmond

City of Albany
City of Asnland
City of Astoria
City of Baker
City of Beaverton
City of Bend
City of Canby
City of Central Point
City of Coos Bay
City of Corvallis
City of Cottage Grove
City of Dallas
City of Eugene, City Manager's Office

City of Eugene, Office of the Mayor
City of Forest Grove
City of Gladstone, Director of Public Works
City of Gladstone, Office of the Mayor
City of Gold Hill, City Recorder
City of Grants Pass
City of Gresham
City of Hermiston
City of Hillsboro
City of Irrigon
City of Klamath Falls
City of La Grande
City of Lake Oswego
City of Lebanon
City of McMinnville
City of Medford
City of Milwaukie
City of Monmouth
City of Mt. Angel, City Administrator
City of Newberg
City of Newport
City of North Bend
City of Ontario
City of Oregon City
City of Pendleton
City of Portland
City of Prineville
City of Roseburg
City of Salem
City of Silverton
City of Sodaville
City of Springfield
City of St. Helens
City of The Dalles
City of Tigard
City of Toledo, City Planner
City of West Linn
City of Woodburn
City of Yoncalla
Clatsop Tillamook Intergovernmental Council, Cannon Beach
Columbia Regional Association of Governments, Portland
Coos Curry Council of Governments, North Bend
Department of Environmental Quality, Portland
District 4 Council of Governments, Corvallis
East Central Oregon Association of Counties, Pendleton
Governor of the State of Oregon, Salem
Klamath Lake Planning and Coordinating Council, Lakeview
Lane Council of Governments, Eugene
Lane Regional Air Pollution Authority, Eugene
League of Oregon Cities, Salem
Metropolitan Service District, Portland
Mid-Columbia Council of Governments, The Dalles
Mid-Columbia Economic Development District, The Dalles
Mid-Willamette Valley Council of Governments, Salem

Multnomah County Community Action Agency, Portland
Northwest Power Planning Council, Portland
Oregon Association of Counties, Salem
Oregon Department of Agriculture, Director, Salem
Oregon League of Cities, Salem
Oregon Public Utilities Commission, Salem
Oregon State Clearinghouse, Intergovernmental Relations Division, Salem
Oregon State Department of Energy, Salem
Oregon State Department of Transportation, Parks & Recreation, Salem
Oregon State Historic Preservation Office, Salem
Oregon State University Extension Service, Corvallis
Oregon State Worker's Compensation Dept, Salem
Rogue Valley Council of Governments, Central Point
State Energy Committee, House of Representatives, Salem
State Energy Committee, Senate, Salem
Umpqua Regional Council of Governments, Roseburg

FEDERAL AGENCIES

U.S. Department of Agriculture

Forest Service, Region 6, Portland
Soil Conservation Service, West Technical Service Center, Portland

U.S. Department of Commerce

National Marine Fisheries Service, Portland

U.S. Department of Housing and Urban Development

John Bonham, Portland

U.S. Department of the Army

Corps of Engineers, North Pacific Division, Portland

U.S. Department of the Interior

Bureau of Indian Affairs, Portland
Bureau of Land Management, Oregon/Washington, Portland
Bureau of Mines, Albany Research Center, Albany
Office of the Secretary, Portland
U.S. Fish and Wildlife Service, Portland

U.S. Attorney's Office, Portland

U.S. General Accounting Office, Portland

Rural Electrification Administration, Eugene

LIBRARIES

Eastern Oregon State College Library, La Grande
Lewis and Clark College, Aubrey R. Watzek Library, Portland
Library Association of Portland, Portland
Linfield College, Northrup Library, McMinnville
Oregon College of Education Library, Monmouth
Oregon State Library, Salem

Oregon State University Library, Documents Division, Corvallis
Oregon Supreme Court Library, Salem
Pacific University, Harvey W. Scott Memorial Library, Forest Grove
Portland State University Library, Documents Librarian, Portland
Reed College, Eric V. Hauser Memorial Library, Portland
Southern Oregon State College Library, Documents Section, Ashland
University of Oregon Library, Documents Section, Eugene
Willamette University Library, Salem

INDIAN TRIBES

Columbia River Inter-Tribal Fish Commission, Portland
Confederated Tribes of Umatilla Reservation, Pendleton

INTEREST GROUPS

1000 Friends of Oregon, Portland
Bay Area Environmental Committee, Coos Bay
Birkenfeld-Mist Citizens' Public Advisory Committee, Rainier
Central Cascades Conservation Council, Salem
Clatskanie-Quincy Citizens' Public Advisory Committee, Clatskanie
Columbia River Citizen's Compact, Portland
Columbia Solar Energy Association, Portland
Concerned Citizens of Oregon, Albany & Crabtree
Direct Service Industries, Inc, Portland
Eco-alliance, Corvallis
Environmental Defense Center, Portland
Eugene Future Power Committee, Eugene
Forelaws on Board, Lloyd Marbet, Boring
Neil Fulton, Portland
Richard M. Glick, Portland
Healthy Environment Action League, Azalea
Izaak Walton League, Portland
Land Air Water, Law School of Oregon, University of Oregon, Eugene
League of Women Voters of Central Lane County, Eugene
League of Women Voters, Portland
Mid-Columbia Concerned Citizens, The Dalles
National Lawyers Guild Energy Committee, Portland
National Wildlife Federation, Portland
Natural Resources Law Institute, Portland
Northwest Council Adequate Electricity Comm, Portland
Northwest Natural Gas, Portland
OMSI Energy Center, Portland
Oregon Common Cause, Portland & Salem
Oregon Consumer League, Portland
Oregon Energy Coordinators Association, Corvallis
Oregon Environmental Council, Portland
Oregon Fair Share, Springfield
Oregon League of Environmental Voters, Portland
Rainier-Fernhill Citizens' Public Advisory Committee, Rainier
Ragen, Roberts, O'Scanlain, Robertson, & Neill, Portland
Ratepayers, Ms. Barbara A. Wanores, Elmira
Rose City Ratepayers Association, Portland
Scappoose-Spitzenberg Citizens' Public Advisory Committee, Scappoose

Solar Energy Assn. of Oregon, Portland
Solar Oregon Lobby, Portland
Southwest Oregon Community Action, Ms. Kathy Oxborrow, North Bend
University of Oregon, Environmental Studies Center, Eugene
Urban Indian Council Inc, Energy Coordinator, Portland
Western Environmental Trade Association, Inc, Portland
Western Oregon Energy Coalition, Vernonia

CUSTOMERS

Alumax Pacific Corp, Portland
Blachley Lane County Coop, Eugene
Canby Utility Board, Canby
Cascade Locks City Light, Cascade Locks
Central Electric Coop Inc, Redmond
Central Lincoln PUD, Newport
CH2M Hill, Portland
City of Ashland, Ashland
City of Bandon, Bandon
City of Drain, Drain
City of Forest Grove, Forest Grove
City of McMinnville, McMinnville
City of Monmouth, Monmouth
Clatskanie PUD, Clatskanie
Columbia Basin Electric Coop, Heppner
Columbia Power Coop Assn, Monument
Columbia River PUD, St Helens
Consumer Power Inc, Corvallis
Coos Curry Electric Coop Inc, Coquille
CP National Corp, Baker
Crown Zellerbach Corp, West Linn
Douglas Electric Coop Inc, Roseburg
Eugene Water & Electric Board, Eugene
Georgia Pacific Corp, Portland
Hanna Nickel Smelting Co, Riddle
Harney Electric Coop Inc, Burns
Hood River Electric Coop, Ouel
Lane Electric Coop Inc, Eugene
Martin Marietta Aluminum Inc, The Dalles
Mid-State Electric Coop Inc, La Pine
Milton-Freewater Light & Power, Milton-Freewater
Oregon Metallurgical Co, Albany
Pacific Carbide & Alloys Co, Portland
Pacific Northwest Generating Co, Portland
Pacific Power & Light Co, Portland
Pennwalt Corp, Portland
Portland General Electric, Portland
Reynolds Metals Co, Portland & Troutdale
Salem Electric, Salem
Springfield Utility Board, Springfield
Surprise Valley Electrification Corp, New Pine Creek
Tillamook PUD, Tillamook
Umatilla Electric Coop Assn, Hermiston
US Dept of the Interior, Bureau of Mines, Albany Research Center, Albany

Wasco Electric Coop Inc, The Dalles
Western Oregon Electric Coop Inc, Vernonia

STATE of UTAH

CITY/COUNTY/STATE GOVERNMENT

Board of County Commissioners, County of Box Elder, Brigham City
Department of Community Affairs, Salt Lake City
Governor of the State of Utah, Salt Lake City
Brigham City, Office of the Mayor, Brigham City
Public Utilities Commission, State of Utah, Salt Lake City
Utah Association of Counties, Salt Lake City
Utah League of Cities & Towns, Salt Lake City
Utah State Office of Energy, Salt Lake City
Utah State Planning Coordinator, Office of the Governor, Salt Lake City
Utah State Historical Society, Salt Lake City

FEDERAL AGENCY

U.S. Department of Agriculture
Forest Service, Region 4, Ogden

CUSTOMERS

Utah Power & Light Co, Salt Lake City

STATE of WASHINGTON

CITY/COUNTY/STATE GOVERNMENT

Association of Elected County Officials, Olympia
Benton-Franklin Governmental Conference, Richland
Board of County Commissioners

County of:

Adams, Ritzville
Asotin, Asotin
Benton, Prosser
Chelan, Wenatchee
Clallam, Port Angeles
Clark, Vancouver
Columbia, Dayton
Cowlitz, Kelso
Douglas, Waterville
Ferry, Republic
Franklin, Pasco
Garfield, Pomeroy
Grant, Ephrata

Grays Harbor, Montesano
Island, Coupeville
Jefferson, Port Townsend
King, Seattle
Kitsap, Port Orchard
Kittitas, Ellensburg
Klickitat, Goldendale
Lewis, Chehalis
Lincoln, Davenport
Mason, Shelton
Okanogan, Okanogan
Pacific, South Bend
Pend Oreille, Newport
Pierce, Tacoma
San Juan, Friday Harbor
Skagit, Mount Vernon
Skamania, Stevenson
Snohomish, Everett
Spokane, Spokane
Stevens, Colville
Thurston, Olympia
Wanakiakum, Catlamet
Walla Walla, Walla Walla
Whatcom, Bellingham
Whitman, Colfax
Yakima, Yakima

Chamber of Commerce, Tacoma Pierce County, Tacoma

City of Aberdeen
City of Anacortes
City of Auburn
City of Bellevue, City Manager
City of Bellevue, Office of the Mayor
City of Bellingham
City of Bremerton
City of Blaine
City of Camas
City of Centralia
City of Chehalis
City of Cheney
City of Chewelah
City of Clarkston
City of College Place
City of Des Moines
City of Eastsound
City of Edmonds
City of Ellensburg
City of Enumclaw
City of Ephrata
City of Fircrest
City of Hoquiam
City of Kelso
City of Kennewick
City of Kent
City of Kirkland

City of Lacey
 City of Langley
 City of Longview
 City of Lynnwood
 City of Mercer Island
 City of Moses Lake
 City of Mount Vernon
 City of Mountlake Terrace
 City of Oak Harbor
 City of Olympia
 City of Pasco
 City of Port Townsend
 City of Puyallup
 City of Renton
 City of Richland
 City of Seattle
 City of Sedro-Woolley
 City of Shelton
 City of Snohomish
 City of Spokane
 City of Sunnyside
 City of Tacoma, Office of Intergovernmental Affairs
 City of Toppenish
 City of Tumwater
 City of Vancouver
 City of Walla Walla
 City of Wenatchee
 City of Yakima
 Clallum-Jefferson Community Action Council, Port Townsend
 Clark County Regional Planning Council, Vancouver
 Community Action Council, Aberdeen
 Conference of Governments, Grant-Lincoln-Adams County, Ephrata
 Cowlitz County Cooperative Extension, Kelso
 Cowlitz-Wanakiakum Governmental Conference, Kelso
 Department of Community Development, County of Cowlitz, Kelso
 Department of Ecology, Olympia
 Department of Human Resources, Seattle
 Department of Labor and Industries, Olympia
 Governor of the State of Washington, Olympia
 Grays Harbor Regional Planning Comm, Aberdeen
 Jefferson-Port Townsend Regional Comm, Port Townsend
 Kittitas Council of Governments, Ellensburg
 Klickitat Regional Council, Goldendale
 Lewis Regional Planning Comm, Chenallis
 Mason Regional Planning Council, Shelton
 Northwest Power Planning Council, Olympia
 Office of Archaeology and Historic Preservation, Olympia
 Office of Community Development, Director, Olympia
 Okanogan Regional Planning Council, Okanogan
 Pacific County Regional Planning Council, South Bend
 Puget Sound Council of Government, Seattle
 Regional Planning Commission, East Wenatchee
 Senate Energy & Utilities Comm., Olympia
 Skagit Regional Planning Council, Burlington

Skamania Regional Planning Council, Stevenson
Spokane Regional Planning Council, Spokane
State Energy Committee, House of Representatives, Olympia
State Energy Committee, Senate, Olympia
State of Washington Labor Council, Seattle
Thurston Regional Planning Council, Olympia
Trico Economic Development District, Colville
Washington Association of Counties, Olympia
Washington Association of Cities, Seattle
Washington State Department of Ecology, Central Regional Office, Yakima
Washington State Department of Ecology, Environmental Review Section, Olympia
Washington State Department of Labor & Industry, Olympia
Washington State Department of Revenue, Olympia
Washington State Energy Office, Olympia
Washington State Parks and Recreation Commission, Olympia
Washington Utilities & Transportation Commission, Olympia
Whatcom County Council of Governments, Bellingham
Whatcom County Opportunity Council, Bellingham
Whitman County Regional Planning Council, Colfax
Yakima Valley Conference of Governments, Yakima

FEDERAL AGENCIES

Environmental Protection Agency

Environmental Evaluation Branch, Seattle
Region X, Seattle

Federal Regional Council

Region X, A-95 Coordinator, Seattle

U.S. Department of Commerce

National Oceanic and Atmospheric Administration, Seattle
National Marine Fisheries Service NW Region
Office of General Counsel

U.S. Department of Energy

Region X, Seattle
Richland
Hanford Operations Office, Richland
Richland Operations Office, Office of Chief Counsel, Richland

U.S. Department of Housing and Urban Development

Regional Office of CPD, Seattle

U.S. Department of the Army

Corps of Engineers, Seattle District, Seattle
Corps of Engineers, Walla Walla District Office, Walla Walla

U.S. Department of the Interior

Bureau of Indian Affairs, Olympic Peninsula Agency, Hoquiam;
Spokane Agency, Wellpinit; and Western Washington Agency, Everett
and Wapato
Bureau of Land Management, Spokane
Bureau of Mines, Western Field Operations Center, Spokane
National Park Service, Pacific Northwest Region, Seattle

U.S. Department of Transportation

Federal Aviation Administration, Northwest Region,
Logistics Division, Seattle

LIBRARIES

Central Washington State College Library, Documents Department, Ellensburg
Eastern Washington State College, Memorial Library, Cheney
Everett Community College Library, Everett
Everett Public Library, Everett
Evergreen State College, Daniel J. Evans Library, Olympia
Fort Vancouver Regional Library, Vancouver
Mid-Columbia Library, Kennewick
North Olympic Library System, Library Service Center, Port Angeles
Pierce County Rural Library District, Tacoma
Port Angeles Public Library, Port Angeles
Seattle Public Library, Documents Librarian, Seattle
Seattle Public Library, Governmental Research Assistance, Seattle
Spokane Public Library, Spokane
Tacoma Public Library, Tacoma
University of Puget Sound Library, Tacoma
University of Washington, Government Publications Section, Seattle
University of Washington, Henry Suzzallo Memorial Library, Seattle
University of Washington, School of Law Library, Seattle
Washington State Library, Documents Center, Olympia
Washington State University Library, Serial-Record Section, Pullman
Western Washington State College Library, Documents Division, Bellingham
Whitman College, Northwest Collection, Walla Walla

INDIAN TRIBES

Colville Confederated Tribes, Nespelem
Spokane Tribe of Indians, Wellpinit
Swinomish Tribal Community, Laconner

INTEREST GROUPS

Battelle Pacific NW Laboratories, Richland
Bill Bayne, Bellevue
Ronald Bowen, Olympia
Larry Caldwell, Richland
Citizens for a Better Government, Vancouver
Citizens for a Solar Washington, Seattle
Citizens-Solar-Washington, Seattle
Clark County Citizens for a Solar Washington, Vancouver
Common Cause, State Director, Olympia
Communities United for Responsible Energy, Toledo
Cooperative Extension, Vancouver
Don't Bankrupt Washington, Seattle
Downtown Neighborhood Alliance, Seattle
Elder Citizens Coalition of Washington, Seattle
Energy Resource Center, Ellensburg
Environmental Affairs Commission, University of Washington, Seattle
Environmental Law Committee of Young Lawyer's Section of
Seattle-King County Bar Association, Seattle

Fair Electric Rates Now (FERN), Olympia
 Fair Use Snohomish Energy, Edmonds
 FUSE, Everett
 Gary Galbreath, Ritzville
 Green Giant Company, Dayton
 Huxley Environmental Reference Bureau, Western Washington Univ., Bellingham
 Inland Empire Solar Energy Assn, Spokane
 Institute for Environmental Studies, Univ of WA, Seattle
 Irate Taxpayers Ellensburg Chapter, Ellensburg
 Earl M. Jorgensen Company, Seattle
 Kittitas Valley Alternate Energy Association, Ellensburg
 Klickitat Skamania Community Action, White Salmon
 KNDU-TV, Tri-Cities
 League of Women Voters, Seattle
 Light Brigade, Bill Ferguson, Seattle
 Longview Fibre Company, Longview
 Lower Columbia Community Action, Longview
 Neil MacDonald, Seattle
 Mason County Energy Ed Group, Shelton
 Metnow Solar Energy Assn, Twisp
 Mid-Columbia Solar Energy Assn, White Salmon
 Municipal Res & Services Center, Seattle
 Neighborhood Weatherization, Seattle
 North Cascades Conservation Council, Seattle
 Northeast Washington Appropriate Creative Technology, Republic
 Northwest Conservation Act Coalition, Seattle
 Northwest Council for Adequate Electricity, Bellevue
 Northwest Fund for the Environment, Seattle
 Olympic Alternative Center, Port Townsend
 Pierce County Action, Tacoma
 Preserve Agricultural Land, Pasco
 Puget Sun, Tacoma
 R. W. Beck & Associates, Seattle
 Real Irate Ratepayers, Longview
 Recreational Equipment Inc, Seattle
 Eric Hedman, Seattle
 Ryegrass Energy Resource Group, Walla Walla
 Seattle Gray Panthers, Seattle
 Snapiro & Associates, Inc, Seattle
 Sierra Club, Seattle
 Solar Energy Association, Snohomish County, Edmonds
 Solar Trades Council, Seattle
 South Columbia Basin Irrigation District, Pasco
 Southern Puget Sound Solar Environmental Association, Olympia
 Donald Stark, Seattle
 Mark Sullivan, Seattle
 Synergic Resources Corp, Seattle
 Tri-Cities Solar Energy Society, Pasco
 George Tuerk, Seattle
 Washington Environmental Council, Seattle
 Washington Public Power Supply System, Richland
 Washington State Sportsmen's Council, Tacoma
 Washington State University, Pullman
 Western Environmental Trade Association, Bellevue

Western Resources Institute, Seattle
Western Washington Solar Energy Assn, Seattle
Whatcom Solar Association, Bellingham
Whidbey Island Solar Energy Association, Clinton
Yakima Solar Energy Assn, Yakima

CUSTOMERS

Alder Mutual Light Co, Eatonville
Aluminum Company of America, Vancouver & Wenatchee
Arco Metals Co, Vancouver
Benton County PUD #1, Kennewick
Benton Rural Electric Assn, Prosser
Big Bend Electric Cooperative, Ritzville
Centralia City Light Dept, Centralia
CH2M Hill, Bellevue
Chelan County PUD #1, Wenatchee
City of Blaine, Blaine
City of Cheney, Cheney
City of Coulee Dam, Coulee Dam
City of Ellensburg, Ellensburg
City of Port Angeles, Port Angeles
City of Richland, Richland
City of Sumas, Sumas
Ciallum County PUD #1, Port Angeles
Clark County PUD, Vancouver
Columbia Rural Electric Assn Inc, Dayton
Consolidated Irrigation District 19, Greenacres
Cowlitz County PUD #1, Longview
Crown Zellerbach Corp, Seattle
Douglas County PUD #1, East Wenatchee
Elmherst Mutual Power & Light Co, Tacoma
Ferry County PUD #1, Republic
Franklin County PUD, Pasco
Georgia Pacific Corp, Bellingham
Grant County PUD, Ephrata
Grays Harbor County PUD #1, Aberdeen
Inland Power & Light Co, Spokane
Intalco Aluminum Corp, Ferndale
Kaiser Aluminum & Chemical Corp, Spokane, Tacoma, Trentwood & Vancouver
Kittitas County PUD #1, Ellensburg
Klickitat County PUD, Goldendale
Lakeview Light & Power Co, Tacoma
Lewis County PUD, Chenalis
Lincoln Electric Coop Inc, Davenport
Mason County PUD #1, Shelton
Mason County PUD #3, Shelton
Nespelem Valley Electric Coop, Nespelem
Onop Mutual Light Co, Eatonville
Okanogan County Electric Coop Inc, Wintthrop
Okanogan County PUD #1, Okanogan
Orcas Power & Light Co, Eastsound
Pacific County PUD #2, Raymond
Parkland Light & Water, Tacoma

Pend Oreille County PUD #1, Newport
Peninsula Light Co, Gig Harbor
Pennwalt Corp, Tacoma
Puget Sound Power & Light Co, Bellevue
Reynolds Metals Co, Longview
Seattle City Light, Seattle
Skamania County PUD, Carson
Snohomish County PUD, Everett
Tacoma City Light, Tacoma
Tanner Electric Coop, North Bend
The Washington Water Power Co, Spokane
Town of Eatonville, Eatonville
Town of Fircrest, Fircrest
Town of Milton, Milton
Town of Steilacoom, Steilacoom
US Dept of the Air Force, Base Contracting Officer, Fairchild AFB
US Dept of the Interior, Bureau of Reclamation, Ephrata & Yakima
US Dept of the Navy
 Bangor Naval Station, Bremerton
 Naval Radio Station T, Oso
 Puget Sound Naval Shipyard, Bremerton
Vera Irrigation District #15, Veradale
Wahkiakum County PUD, Cathlamet
Wnatcom County PUD #1, Bellingham

WASHINGTON D.C.

FEDERAL AGENCIES

Boards, Committees & Commissions

 Advisory Council on Historic Preservation

Environmental Protection Agency

 Interagency Research Group, Indoor Air Quality

U.S. Department of Agriculture

 Office of the Secretary

 Rural Electrification Administration

U.S. Department of Commerce

 National Oceanic & Atmospheric Administration

 Ecology & Conservation Division

U.S. Department of Energy

 Assistant Secretary, Intergov. Institutional Relations

 Federal Energy Regulatory Commission

 Library FOI, Public Reading Room

U.S. Department of the Army

 Corps of Engineers, Executive Director of Civil Works

U.S. Department of the Interior

Bureau of Indian Affairs
Bureau of Reclamation
Office of Environmental Project Review
Office of the Secretary
Bureau of Mines
National Park Service

U.S. Department of Transportation

Federal Aviation Administration,
Assistant Secretary for Environmental and Urban Systems

Water Resources Council

CONGRESSIONAL COMMITTEES

Committee on Appropriations, House of Representatives
Energy Conservation & Power Subcommittee, House of Representatives
Energy & Natural Resources Committee, United States Senate
Energy & Water Development Subcommittee, House of Representatives
Interior & Insular Affairs Committee, House of Representatives
 Subcommittee on Mines and Mining, Forest Management and the
 Bonneville Power Administration
Subcommittee on Oversight & Investigations, House of Representatives
Water & Power Resources Subcommittee, House of Representatives

U.S. SENATORS

The Honorable:
Max Baucus
Alan Cranston
Jake Garn
Slade Gorton
Orrin G. Hatch
Mark O. Hatfield
Cnic Hecht
Office of the Late
 Henry M. Jackson
Paul Laxalt
James McClure
John Melcher
Robert Packwood
Alan Simpson
Steven Symms
Malcom Wallop
Peter Wilson

CONGRESSIONAL REPRESENTATIVES

The Honorable:
Les Aucoin
Don. L. Bonker
Richard Cheney
Larry Craig

Norman D. Dicks
Thomas S. Foley
George V. Hansen
James Hanson
Michael Lowry
Ronald C. Marlenee
Don Marriott
Sid Morrison
Howard C. Nielson
Joel Pritchard
Harry Reid
Bob Smith
Denny Smith
Al Swift
Barbara Vucanovich
James Weaver
Pat Williams
Ron Wyden

INTEREST GROUPS

Environmental Defense Fund
Friends of the Earth
Morgan, Lewis & Bockius
National Wildlife Federation, Water Resources Program

STATE of WYOMING

CITY/COUNTY/STATE GOVERNMENT

Board of County Commissioners:

County of:

Lincoln, Kemmerer

Teton, Jackson

Governor of the State of Wyoming, Cheyenne

Office of the Mayor, City of Jackson, Jackson

Office of the Governor, State Planning Coordinator, Cheyenne

Public Utilities Commission, State of Wyoming, Cheyenne

Wyoming Association of Municipalities, Cheyenne

Wyoming Recreation Commission, Cheyenne

CUSTOMER

Lower Valley Power & Light Inc, Afton

OTHER STATES

FEDERAL AGENCIES

Boards, Committees & Commissions

Tennessee Valley Authority, Chattanooga & Knoxville, Tennessee

U.S. Department of Energy

Alaska Power Administration, Juneau & Anchorage, Alaska

Oak Ridge National Laboratory, Oak Ridge, Tennessee

Southeastern Power Administration, Elberton, Georgia

Southwestern Power Administration, Tulsa, Oklahoma

U.S. Department of Health & Human Services

Public Health Service, Environmental Health Services Division,

Center for Disease Control, Atlanta, Georgia

CUSTOMERS

Aluminum Company of America, Pittsburgh, Pennsylvania

Arco Metals Co, Rolling Meadows, Illinois & Louisville, Kentucky

Elkem Metals Co, Niagara Falls, New York & Pittsburgh, Pennsylvania

Hanna Mining Co, Cleveland, Ohio

Martin Marietta Aluminum Inc, Bethesda, Maryland

Reynolds Metals Co, Richmond, Virginia

Stauffer Chemical Co, Westport, Connecticut & Mt Pleasant, Tennessee

The Carborundum Co, Niagara Falls, New York

Union Carbide Corp, Danbury, Connecticut

STATE AGENCIES

City of Millville Community Dev, Millville, New Jersey

City of New York, Dept of Consumer Affairs, New York, New York

Department of Public Service, Albany, New York

INTEREST GROUPS

Center for Urban Affairs and Policy Research, Evanston, IL

Wells Eddleman, Durham, NC

Linwood Morrell, New York, NY

Daniel Read, Chapel Hill, NC

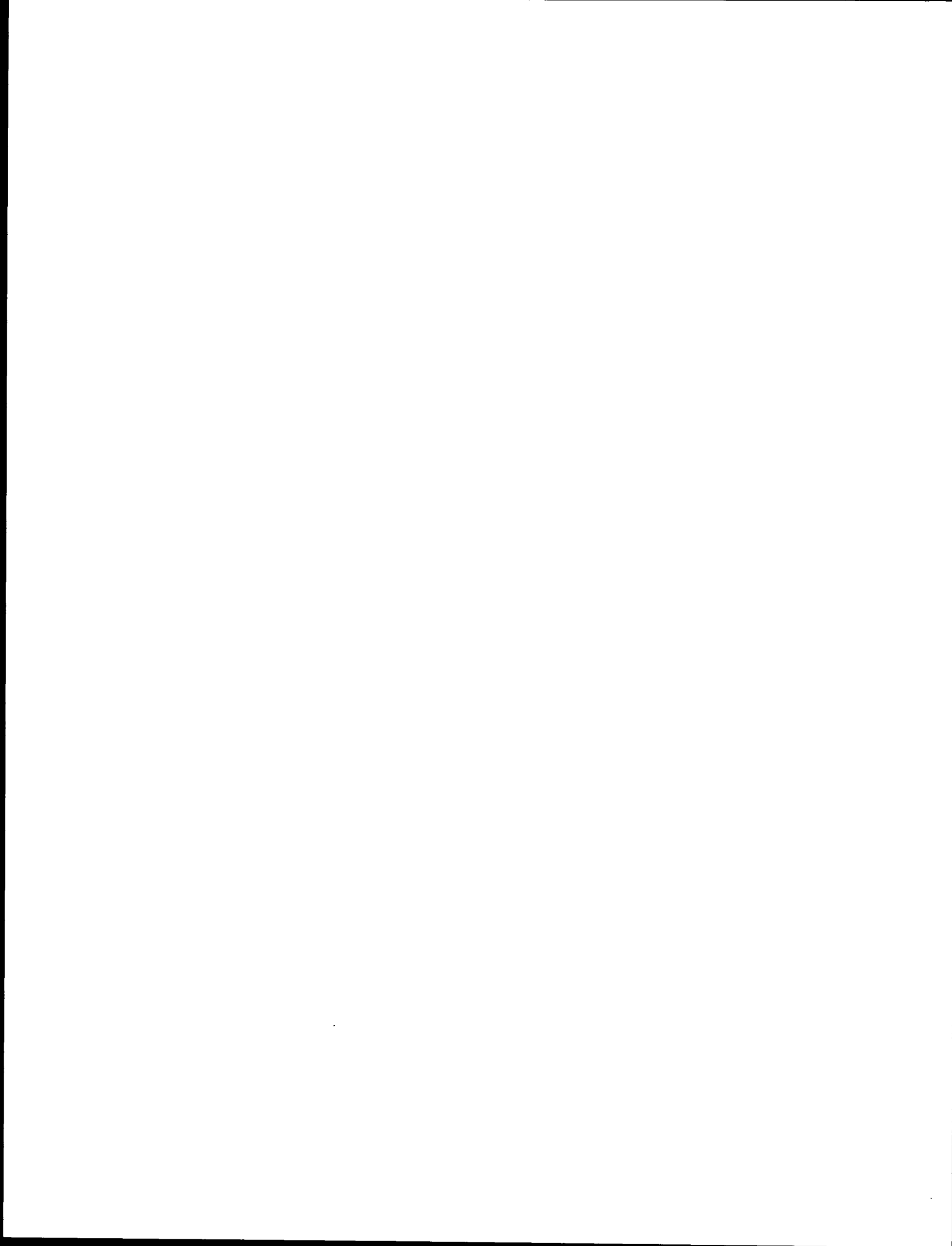
Science Applications, Inc, McLean, VA

CANADA

CUSTOMERS

BC Hydro & Power Authority, Vancouver, British Columbia

(WP-SJ-19530)



Chapter IX

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IX. Bibliography

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Bonneville Power Administration, 1982f, Environmental Assessment of Energy Conservation Opportunities in Commercial Sector Facilities in the Pacific Northwest, U.S. Department of Energy, August.

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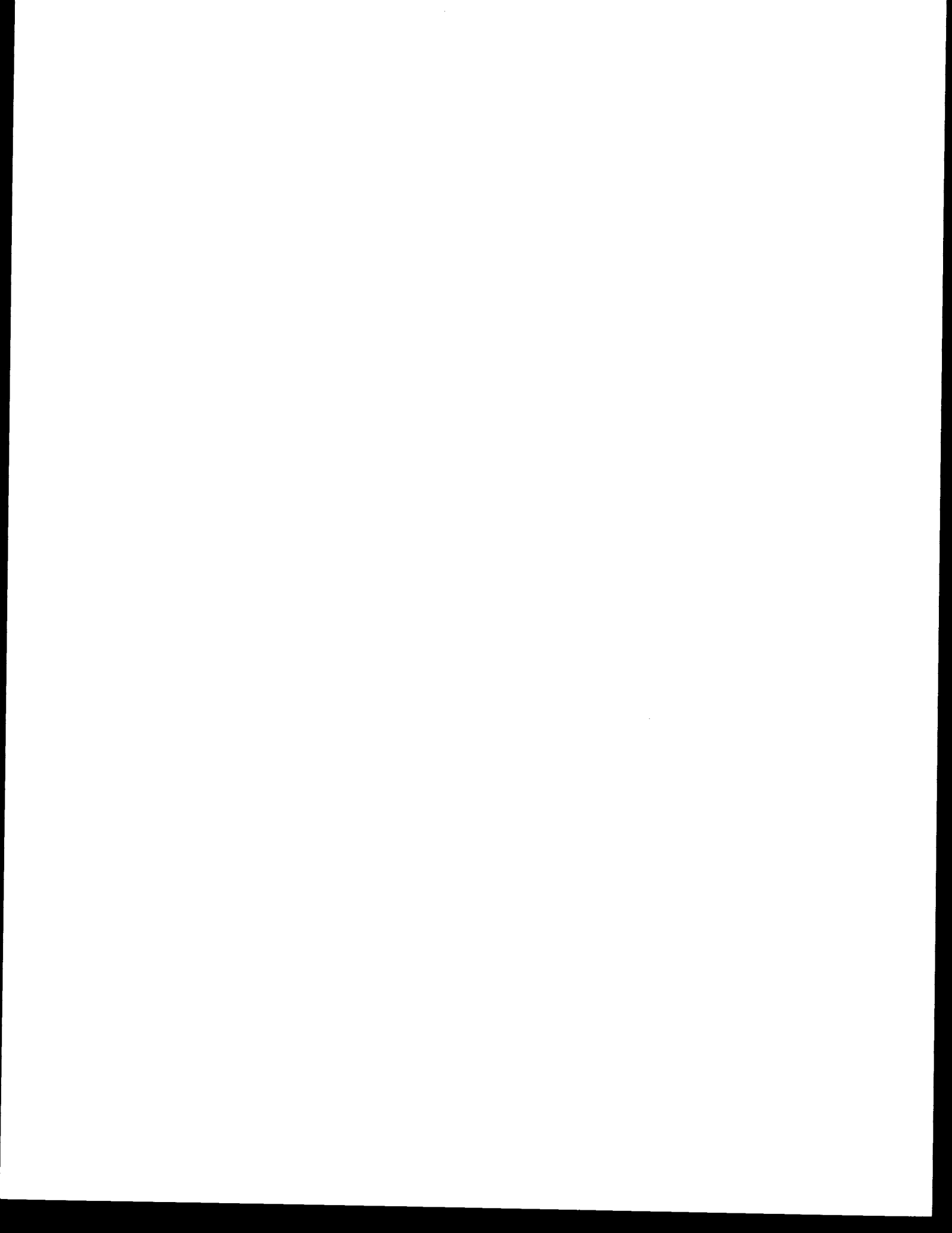
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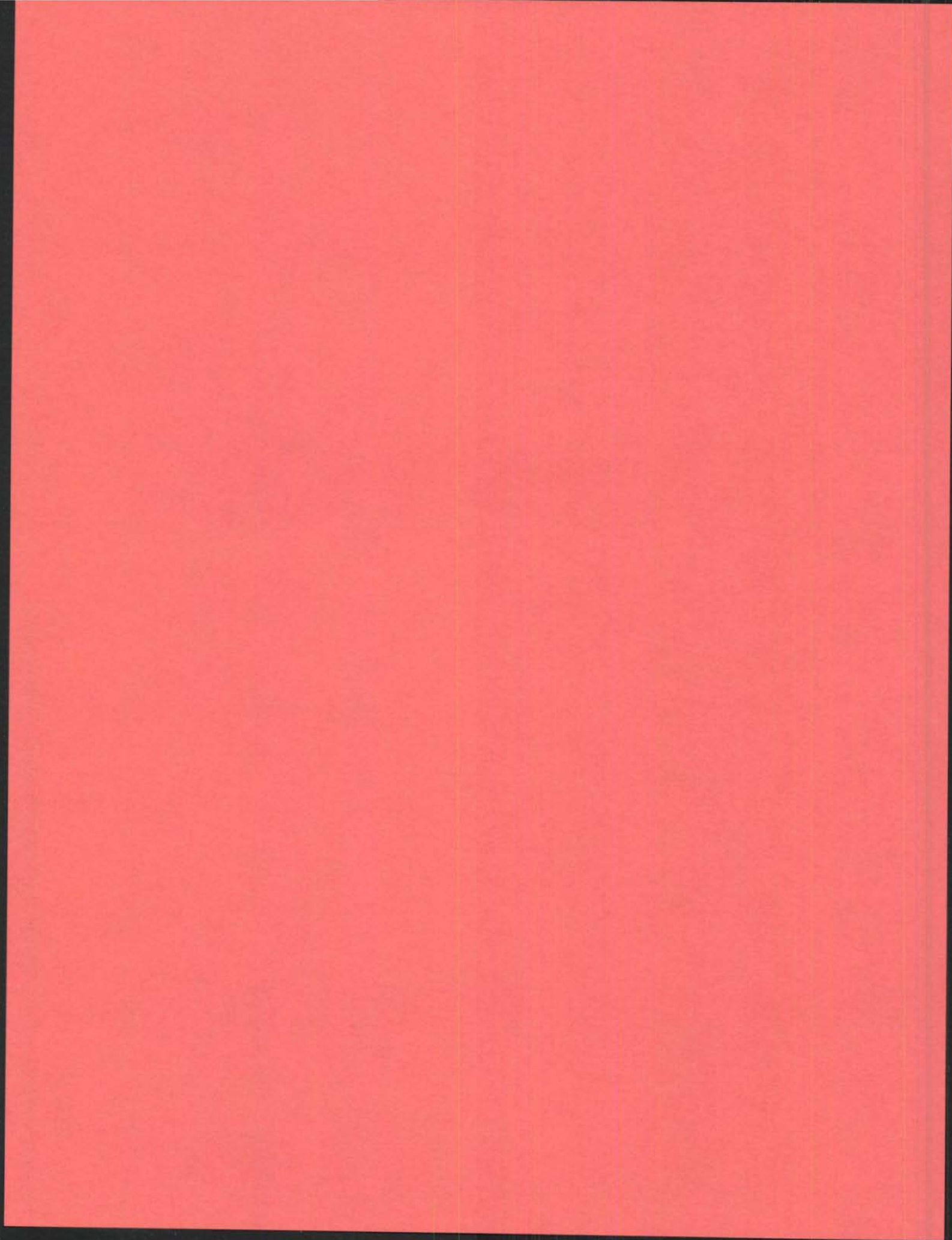
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Chapter X

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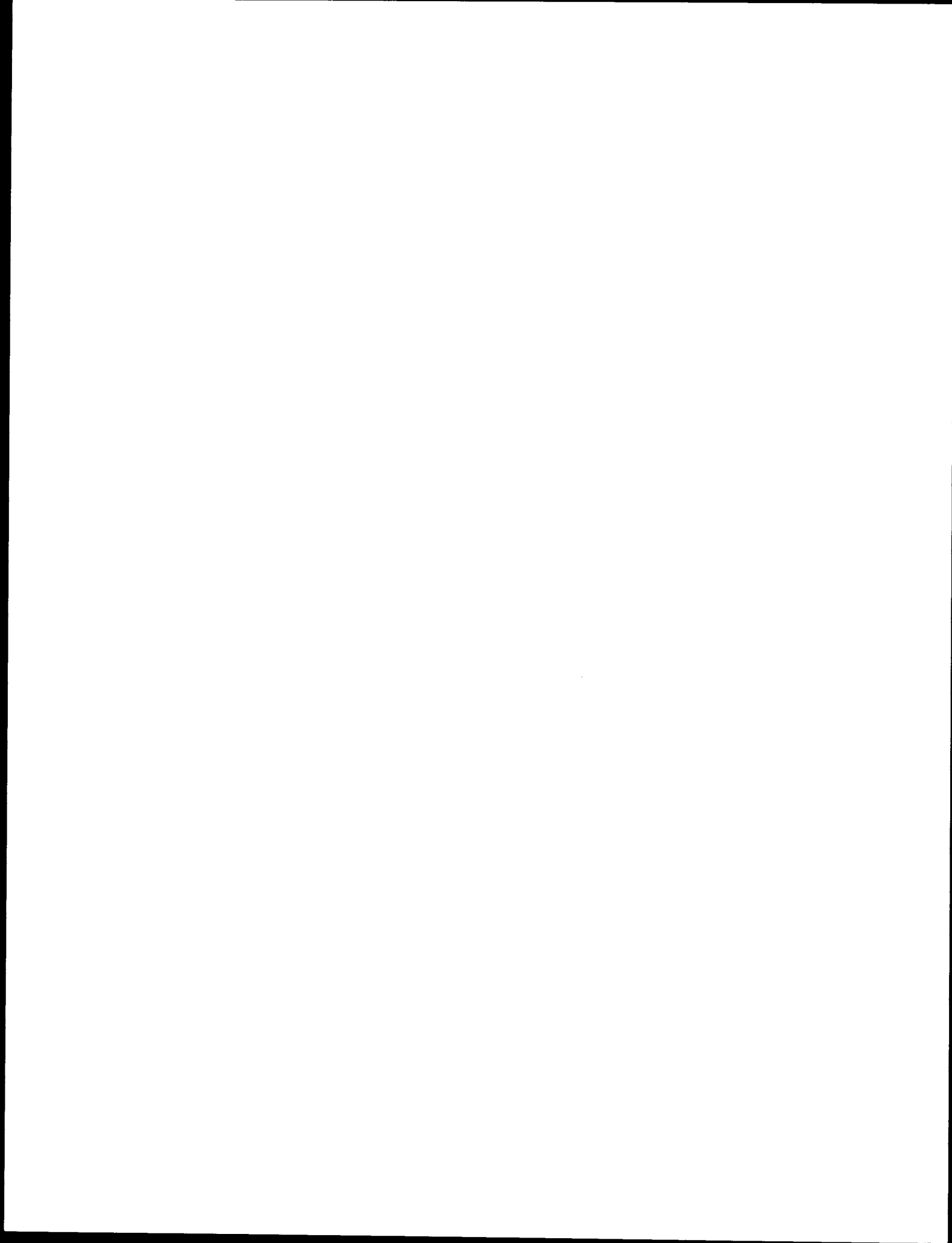
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Appendix A

Existing Rate Schedules

Appendix A

Wholesale Power Rate Schedules

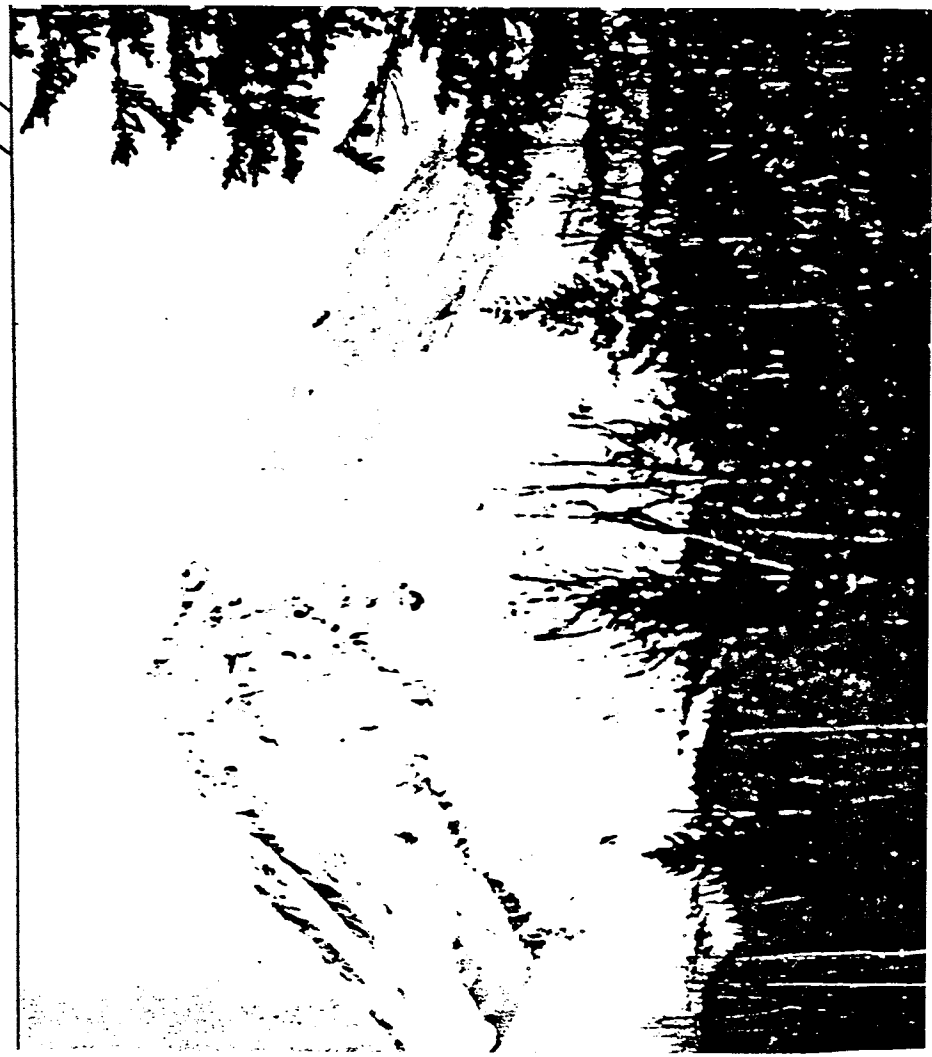
and General Schedule Provisions

1982



DOE/RS-88

Bonneville Power Administration
U.S. Department of Energy



UNITED STATES DEPARTMENT OF ENERGY

Bonneville Power Administration

1002 N.E. Holladay
Portland, Oregon 97232

Bonneville Power Administration's 1982 Wholesale Power Rate Schedules and General Rate Schedule Provisions, contained herein were approved on an interim basis effective October 1, 1982. These rate schedules and provisions were approved by the Federal Energy Regulatory Commission, United States Department of Energy, in a Commission Order issued September 29, 1982 (Docket No. EF82-2011).

These rate schedules and provisions supersede in their entirety the Administration's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective July 1, 1981.

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SCHEDULE PF-2 PRIORITY FIRM POWER RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

a. Demand Charge:

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

b. Energy Charge:

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

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule and the purchasers to whom the factors apply are detailed in parts 3a, 3b, 3c, and 3d of this section.

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

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

b. Purchasers designated by Bonneville Power Administration (BPA) to purchase on a computed re-

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

- (i) such purchaser has generation of its own which can be sold in such a way as to increase BPA's obligation to deliver firm power to that purchaser because of such sale; or
- (ii) such purchaser has the ability to redistribute generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal system.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this subsection.

Billing factors for designated computed demand customers will be:

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

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

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

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

- (1) effective July 1, 1982, seventy percent of the energy associated with the utility's residential load for each billing period. The percentage will be increased by ten percentage points each July 1 until 1985 as specified in the contract;
- (2) the demand calculated by applying the load factor, determined as specified in the contract, to the energy in subsection 2d(1) for each billing period.

SECTION 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

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

b. For a purchaser governed by subsection 3b:

- (1) the billing demand for the month shall be 3b(6) if applicable. Otherwise, it shall be the larger of factors 3b(3) and 3b(4). Factor 3b(4), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(8) if applicable, except that at such time as BPA determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1);
- (2) the billing energy for the month shall be factor 3b(5) except that at such time as BPA determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3). Factor 3b(5) shall not exceed factor 3b(2) times the number of hours during the month.

c. For a purchaser governed by subsection 3d:

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

SECTION 5. Adjustments:

a. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser, either at a point of delivery or for a system, at any time that the average power factor for all classes of power delivered to that purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Low-Density Discount:

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

- (1) seven percent if such ratio is less than 15 kilowatthours per dollar of net investment or if the number of consumers per mile of line is two or less;

- (2) five percent if such ratio is equal to or greater than 15 and less than 25 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is four or less;
- (3) three percent if such ratio is equal to or greater than 25 and less than 35 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is six or less.

c. Exchange Adjustment:

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

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

where:

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

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

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

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

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

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

SECTION 6. Unauthorized Increase:

That portion of:

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

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to subsection 6a and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under subsection 6b.

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

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

SCHEDULE IP-2 (MP-2) INDUSTRIAL FIRM POWER RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

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

a. Demand Charge:

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

b. Energy Charge:

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

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

c. Demand Charge:

- (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$4.21 per kilowatt of billing demand;
- (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10

- p.m.: \$1.91 per kilowatt of billing demand;
- (3) all other hours: No demand charge.

d. Energy Charge:

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

SECTION 3. Billing Factors:

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

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

SECTION 4. Determination of Billing Demand and Billing Energy:

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

SECTION 5. Adjustments:

a. Value of Reserves:

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

- (1) \$1.31 per kilowatt of billing demand;
- (2) 0.4 mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under this rate schedule. The value of reserves adjustment is not applicable to customers purchasing modified firm power.

b. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the billing demand for the month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

c. Exchange Adjustment:

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

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

where:

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

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

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

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

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

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

SECTION 6. Unauthorized Increase:

The amount by which any 60-minute clock-hour integrated demand exceeds the sum of:

- a. the billing demand during that hour before adjustment for power factor; and
- b. any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

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

The forecasted average cost of resources available to the Administrator under average water conditions is 18.8 mills per kilowatthour.

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

SECTION 8. General Provisions:

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

**SCHEDULE SI-2
SPECIAL INDUSTRIAL POWER RATE**

SECTION 1. Availability:

This schedule is available for the Hanna Nickel Smelting Company's contract purchase of a special class of industrial power on an operating demand basis and for auxiliary power requested by the purchaser and made available as an auxiliary demand by BPA on an intermittent basis. This rate schedule is made available pursuant to section 7(d)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act).

SECTION 2. Rate:

a. Demand Charge:

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

b. Energy Charge:

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

SECTION 3. Billing Factors:

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

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

SECTION 4. Determination of Billing Demand and Billing Energy:

The billing demand for this special class of industrial power will be the lowest of the respective operating demand, curtailed demand, or restricted demand after such demand is adjusted for power factor. The billing demand for auxiliary power requested by the purchaser and made available by BPA will be the demand for auxiliary power as adjusted for power factor. Dur-

ing any billing month in which there is more than one demand for industrial firm power or auxiliary power, the billing demand for the month will be the weighted average for the billing month of the billing demands. If the purchaser requests auxiliary power during the billing month, the billing demand for auxiliary power will be the weighted average of the billing demands for the number of days during the billing month in which the purchaser received auxiliary power. The billing energy associated with each of the respective billing demands will be the measured energy distributed among the respective billing demands for each period such billing demand is applicable during the billing month.

SECTION 5. Adjustments:

a. Value of Reserves:

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

- (1) \$1.31 per kilowatt of billing demand;
- (2) 0.4 mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under this rate schedule.

b. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the billing demand for the month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 75 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 6. Unauthorized Increase:

The amount by which any 60-minute clock-hour integrated demand exceeds the sum of:

- a. the billing demand during that hour before adjustment for power factor; and
- b. any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of 83 mills per kilowatthour.

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

SCHEDULE CF-2 FIRM CAPACITY RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

a. Contract Year Service:

\$36.72 per kilowatt per year of contract demand, billed monthly at the rate of \$3.06 per kilowatt of contract demand.

b. Contract Season Service:

\$13.30 per kilowatt per season of contract demand, billed monthly during the contract season at the rate of \$2.66 per kilowatt of contract demand.

- c. The capacity rate specified in subsections 2a and 2b above shall be increased by \$.024 per kilowatt-month of billing demand per hour that the purchaser's monthly demand duration exceeds nine (9) hours. The purchaser's demand duration for the month shall be determined by dividing the kilowatt-hours supplied under this rate schedule to a purchaser on the day of maximum kilowatt-hour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand for such month. During periods when BPA does not require the delivery of peaking replacement energy by the purchaser, the additional charge described above will not be applied.

SECTION 3. Billing Factors:

The billing demand will be the contract demand.

SECTION 4. Special Provision:

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

SECTION 5. Exchange Adjustment:

To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0

mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for annual capacity customers will be equal to:

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

For seasonal capacity customers the rebate will be:

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

where:

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

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

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

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

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

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

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

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

SECTION 6. Resource Cost Contribution:

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

The forecasted average cost of resources available to the Administrator under average water conditions is 18.6 mills per kilowatthour.

The forecasted cost of resources to meet load growth

is 28.0 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION 7. General Provisions:

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

SCHEDULE CE-2 EMERGENCY CAPACITY RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

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

SECTION 3. Billing Factors:

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

SECTION 4. Special Provision:

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

SECTION 5. Resource Cost Contribution:

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

The forecasted average cost of resources available to the Administrator under average water conditions is 18.8 mills per kilowatthour.

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

SECTION 6. General Provisions:

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

SCHEDULE FE-2 FIRM ENERGY RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

18.4 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

The contract energy is the billing factor.

SECTION 4. Determination of Billing Energy:

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

SECTION 5. Delivery:

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

SECTION 6. Power Factor Adjustment:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at

which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 7. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the FE-2 rate is 94.4 percent FBS; 5.8 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.8 mills per kilowatthour.

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

SECTION 8. General Provisions:

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

SCHEDULE NR-2 NEW RESOURCE FIRM POWER RATE

SECTION 1. Availability:

This schedule is available for the contract purchase of firm power for resale or for direct consumption by investor owned utilities in the Pacific Northwest under net requirement contracts and by any public body, cooperative, or Federal agency to the extent needed to serve any increase in energy consumption of a load as defined in Section 3(13) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) as interpreted in Notice of Final Action (46 F.R. 44353) (September 3, 1981). This schedule supersedes Schedule NR-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Demand Charge:

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

b. Energy Charge:

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

SECTION 3. Billing Factors:

The factors to be used in determining the billing for power purchased under this rate schedule and the purchasers to whom the factors apply are detailed in parts 3a, 3b, and 3c of this section.

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

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

b. Purchasers designated by BPA to purchase on a computed requirements basis shall be billed in accordance with the provisions of this subsection. A purchaser will be so designated if it has one or

more potential abilities as described in paragraphs (i) and (ii) below, unless its power sales contract was executed after December 5, 1980, and provides otherwise:

- (i) such purchaser has generation of its own which can be sold in such a way as to increase BPA's obligation to deliver firm power to that purchaser because of such sale; or
- (ii) such purchaser has the ability to redistribute generation from its resources over time and in such a manner as to cause losses of power or revenue on the Federal system.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this subsection.

Billing factors for designated computed demand customers will be:

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

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

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

SECTION 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

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

b. For a purchaser governed by subsection 3b:

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

SECTION 5. Adjustments:

a. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to a purchaser

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

b. Exchange Adjustment:

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

$$.882 \times \frac{28.0 - AC}{28.0} \times \text{Bill} \times \left(1 + \frac{\text{INT}}{2}\right);$$

where:

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

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

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

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

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

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

SECTION 6. Unauthorized Increase:

That portion of:

- a. any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA

and the purchaser, or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour; or

- b. the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase.

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to subsection 6a and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under subsection 6b.

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

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

SECTION 1. Availability:

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

SECTION 2. Rate:

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

(1) Demand Charge:

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

(2) Energy Charge:

28.4 mills per kilowatthour of billing energy.

- b. For service with a specific discretionary resource or resources not included in subsection 2a:

(1) Demand Charge:

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

(2) Energy Charge:

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

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

SCHEDULE SP-1 SURPLUS FIRM POWER RATE

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

SECTION 3. Billing Factors:

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

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

SECTION 4. Determination of Billing Demand and Billing Energy:

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

SECTION 5. Adjustments:

a. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Exchange:

To the extent that the average cost of all exchange resources acquired during FY 1983 is less than 28.0

mills per kilowatthour, a rebate will be made to all purchasers under this rate schedule. The rebate for each customer will be equal to:

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

where:

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

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

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

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

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

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

SECTION 6. Unauthorized Increase:

That portion of:

- any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers

on such hour pursuant to contracts between BPA and the purchaser, or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour; or

- the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase.

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to subsection 6a and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under subsection 6b.

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

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

SCHEDULE SE-1 SURPLUS FIRM ENERGY RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

28.4 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

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

- The contract amount of energy for the month;
- The measured energy for the month.

SECTION 4. Determination of Billing Energy:

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

SECTION 5. Delivery:

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

SECTION 6. Adjustments:

a. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically other-

wise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. Exchange Adjustment:

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

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

where:

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

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

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

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

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

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

initially to calculate the rebate. No adjustment in the rebate amount will be made for any such adjustments made after October 1, 1984.

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

SCHEDULE NF-2 NONFIRM ENERGY RATE

SECTION 1. Availability:

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

SECTION 2. Rate:

a. Nonfirm Energy Rate:

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

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

delivery on a guaranteed delivery basis, scheduled amounts may not be changed except when:

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

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

- (3) **Incremental Rate:** For power:

- (e) which is produced or purchased concurrently with the nonfirm sale;
- (b) which BPA may at its option not produce or purchase; and
- (c) whose incremental cost is greater than 16.2 mills per kilowatthour; the rate shall be equal to the incremental cost of that power plus 2.0 mills per kilowatthour.

Incremental cost is defined as all identifiable costs in mills per kilowatthour which BPA would not have incurred if it had chosen not to produce or purchase the power being sold under this rate.

b. Contract Rate:

For contracts that refer to this schedule to determine the value of energy, the rate is 11.2 mills per kilowatthour.

SECTION 3. Delivery:

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

SECTION 4. Resource Cost Contribution:

The approximate cost contribution of different resource categories to the NF-2 standard rate is 98.7 percent FBS and 3.3 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 18.6 mills per kilowatthour.

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

SECTION 5. General Provisions:

Sales of energy under this schedule shall be subject to

the General Rate Schedule Provisions and the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (Pub. L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

SECTION 1. Availability:

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

SECTION 2. Rate:

When a transaction takes place on the Energy Broker System, the buy price and sell price, respectively, will be defined as follows:

- a. the BPA buy price is the estimated decremental or equivalent expense per kilowatthour which would otherwise have been incurred by BPA in generating or purchasing power from alternative sources in lieu of broker energy scheduled for delivery to BPA during that hour; and
- b. the BPA sell price is the estimated incremental or equivalent expense per kilowatthour which would be incurred by BPA in supplying broker energy scheduled for delivery during such hour to the buyer from resources which are available to supply power during that hour as determined by BPA.

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

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

Where: EB-1 = Energy Broker Rate
BP = Quoted Buy Price
SP = Quoted Sell Price

**SCHEDULE EB-1
ENERGY BROKER RATE**

The Energy Broker will identify potential transactions when the sell price is at least 2 mills per kilowatthour less than the buy price. The final transaction rate for brokered nonfirm energy will be based on splitting the difference between quoted buy and sell prices, with the settlement for wheeling charges and energy losses defined in accordance with Exhibit A of the WSCC Broker Transmission Service Agreement.

SECTION 3. Delivery:

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

SECTION 4. Resource Cost Contribution:

The cost contribution of different resource categories to the EB-1 rate is based upon the specific resource(s) offered during the scheduled time of sale.

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

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

SECTION 5. General Provisions:

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

SCHEDULE RP-2 RESERVE POWER RATE

SECTION 1. Availability:

This schedule is available for the purchase of:

- a. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract;
- b. power for which BPA determines no other rate schedule is applicable; or
- c. power to serve a purchaser's firm power loads in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applicable. It is also available for purchase of power by entities outside the United States. This rate schedule supersedes Schedule RP-1 which went into effect on an interim basis on July 1, 1981.

SECTION 2. Rate:

a. Demand Charge:

- (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$8.35 per kilowatt of billing demand;
- (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$4.17 per kilowatt of billing demand;
- (3) all other hours: No demand charge.

b. Energy Charge:

42.3 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors:

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

- a. the contract demand as specified in the contract;
- b. the measured demand;
- c. the contract amount of energy for the month;
- d. the measured energy for the month.

SECTION 4. Determination of Billing Demand and Billing Energy:

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

SECTION 5. Power Factor Adjustment:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95 percent. Such average power factor is to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal system, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 6. Unauthorized Increase:

That portion of:

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

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to subsection 6a and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such

month in determining the amount which may be considered an unauthorized increase under subsection 6b.

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

SECTION 7. Resource Cost Contribution:

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

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

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

SECTION 8. General Provisions:

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

GENERAL RATE SCHEDULE PROVISIONS

SECTION 1.1. Priority and New Resource Firm Power:

Priority and new resource firm power is electric power which BPA will make continuously available to a purchaser to meet its actual firm load requirements within the Pacific Northwest except when restricted because the operation of generation or transmission facilities used by BPA to service such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of priority and new resource firm power shall not be made until industrial firm power has been restricted in accordance with Section 1.4 and until modified firm power has been restricted in accordance with Section 1.2. The New Resource Firm Power Rule is applicable to any increase in energy consumption of a load as defined in Section 3(13) of the Pacific Northwest Electric Power Planning and Conservation Act or, when applicable, section 8 of the final utility power sales contract offered August 28, 1981 as published in the Notice of Final Action Concerning Power Sales and Residential Exchange Contracts Required by Pacific Northwest Electric Power Planning and Conservation Act (46 FR 44353) September 3, 1981.

SECTION 1.2. Modified Firm Power:

Modified firm power is electric power which BPA will make continuously available to a purchaser on a contract demand basis subject to:

- a. the restriction applicable to priority and new resource firm power; and
- b. the following:
 - (1) When a restriction is made necessary because the operation of generation or transmission facilities used by BPA to serve a modified firm power purchaser and any priority or new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, BPA shall restrict such purchaser's Contract Demand for Modified Firm Power to the extent necessary to prevent, if possible, or minimize

restriction of any priority and new resource firm power, provided, however that:

- (a) such restriction of modified firm power shall not exceed at any time 25 percent of the contract demand therefor, and
- (b) the accumulation of such restrictions of modified firm power during any calendar year, expressed in kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

SECTION 1.3. Firm Capacity:

Firm capacity means capacity which BPA assures will be available to a purchaser in amounts and during the periods specified in the contract except when operation of the generation or transmission facilities used by BPA to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 1.4. Industrial Firm Power:

Industrial firm power is electric power which BPA will make continuously available to a purchaser on a Contract Demand Basis subject to:

- a. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the contract, and
- b. the following:
 - (1) the restrictions given in the Restriction of Deliveries Section of the contract; and
 - (2) when a restriction is made necessary because of the operation of the generation or transmission facilities used by BPA to serve an industrial firm power purchaser, and any priority

or new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. BPA shall restrict such purchaser's Operating Demand for Industrial Firm Power to the extent necessary to prevent, if possible, or minimize restriction of priority and new resource firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract and operating demands bear to one another. The extent of such restrictions shall be limited for modified firm power by Section 1.2(b) of these General Rate Schedule Provisions and for industrial firm power by the Restrictions of Deliveries Section of the contract.

SECTION 1.5. Authorized Increase:

An authorized increase is an amount of electric power specified in the contract in excess of the contract or operating demand for priority firm power, new resource firm power, modified firm power, industrial firm power as sold under the interim firm contract, or that BPA may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. BPA will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

SECTION 1.6. Firm Energy:

Firm energy is energy which BPA assures will be available to a purchaser during the period or periods specified in the contract except during hours as may be specified in the contract and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 2.1. Contract Demand:

The contract demand shall be the number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available. BPA may agree to make deliveries at a rate in excess of the contract demand at the request of the purchaser (authorized increase), but shall not be obligated to continue such excess deliveries.

SECTION 2.2. Auxiliary Demand:

Auxiliary demand is the number of kilowatts in excess of operating demand that a direct-service industrial purchaser requests and that BPA is able to make available to serve that purchaser's load. After the purchaser makes such a request, BPA will determine whether such demand can be made available. BPA shall retain the right to restrict the delivery of energy to supply such auxiliary power demand if it determines at any subsequent time that auxiliary power is no longer available. The purchaser may curtail deliveries of auxiliary power by written notice to BPA given at least 24 hours prior to the first day of any month.

SECTION 2.3. Measured Demand:

The purchaser's measured demand will be determined according to this section unless the terms of a contract executed after December 5, 1980 provide otherwise. Except where deliveries are scheduled as hereinafter provided, the measured demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands at which electric energy is delivered to a purchaser at each point of delivery during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the contract, or as determined in Section 2.6 herein. BPA, in determining the measured demand, will exclude any abnormal 60-minute integrated demands due to or resulting from:

- a. emergencies or breakdowns on, or maintenance of, the Federal system facilities; and
- b. emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA.

For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the contract. The portion of the total measured demand so assigned shall constitute the measured demand for each such class of power.

If the flow of electric energy to a purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal system, the purchaser's measured demand for each class of power for such system for any billing period shall be based on ratchet demand.

SECTION 2.4. Peak Computed Demand and Energy Computed Demand:

The purchaser's peak computed demand and energy computed demand will be determined according to this section unless terms of a contract executed after December 5, 1980 provide otherwise.

The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability.

a. General Principles:

- (1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.
- (2) As used in this section, "year" shall mean the 12-month period commencing July 1.
- (3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least requirement for capacity and energy on BPA.
- (4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.
- (5) Prior to the beginning of each year the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period.

The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on BPA. Such assured capability shall be effective after review and approval by BPA.

- (6) The purchaser's assured energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on BPA within each year of the critical period with such requirement increasing each year not in excess of the purchaser's annual load growth.
- (7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver on a firm basis to its load. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to BPA. BPA may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if BPA determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.
- (8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability:

The purchaser's assured peaking and energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated, and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate reserves. Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

- (1) **Hydroelectric Generating Facilities:** The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average

energy using critical water conditions. The average energy capability shall be that capability which would be available under the storage operation necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy computed demand for a period of one (1) month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify BPA in writing of the assured energy capability to be applied tentatively to the preceding month; such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured energy capability to be applied to the preceding month; provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by BPA, shall demonstrate by a suitable regulation study based on critical water conditions that such change could actually be accomplished, and that the remaining balance of its total critical period assured energy capability could be developed without adversely affecting the firm capability of other purchaser's resources. The algebraic sum of all such changes in the purchaser's assured energy capability shall be zero at the end of the

critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation indicated by such revisions in the monthly distribution of critical period energy capability.

- (2) **Thermal Generating Facilities:** The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.
- (3) **Other Sources of Power:** The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. **Determination of Computed Demand:** The purchaser's computed demand for each billing month shall be the greater of:

- (1) the largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or
- (2) the largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own

load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of priority and new resource firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

SECTION 2.5. Restricted Demand:

A restricted demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when BPA has restricted delivery of such power for one (1) clock-hour or more. Such restrictions by BPA are made pursuant to the power sales contract for industrial firm power and pursuant to Section 1.1 and 1.2 of the General Rate Schedule Provisions for priority and new resource firm power and modified firm power, respectively. Such restricted demand shall be determined by BPA after the purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with Section 2.6 of the General Rate Schedule Provisions.

SECTION 2.6. Curtailment Demand:

A curtailed demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, auxiliary power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the contract. Each purchaser of an authorized increase in excess of priority firm power, new resource firm power, or modified firm power may curtail its demand in accordance with Section 1.5 of the General Rate Schedule Provisions.

SECTION 3.1. Temporary Curtailment of Contract Demand:

The reduction of charges for power curtailed pursuant to the purchaser's contract and Section 1.5 and 2.6 hereof shall be applied in a uniform manner.

SECTION 4.1. Energy Supplies for Emergency Use:

A purchaser taking priority and/or new resource firm power shall pay in accordance with Wholesale Non-firm Energy Rate Schedule NF-2 and Emergency Capacity Schedule CE-2 for any electric energy or capacity which has been supplied:

- for use during an emergency on the purchaser's system; or
- following an emergency to replace energy secured from sources other than BPA during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

SECTION 5.1. Application of Rates During Initial Operation Period:

For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree:

- to bill for service to such new, additional, or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor; or
- if such facilities are served by a distributor purchasing power therefor from BPA to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor.

Any rate schedule provisions regarding contract demand, billing demand, and minimum monthly charge which are inconsistent with this Section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by BPA, be extended beyond the initial 3 month period for such additional time as is justified by the developmental character of the operations.

SECTION 6.1. Billing:

Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when:

- delivery at more than one point is beneficial to BPA; or
- the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

SECTION 6.2. Determination of Estimated Billing Data:

If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

SECTION 7.1. Billing Month:

Meters will normally be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

SECTION 8.1. Payment of Bills:

Bills for power shall be rendered monthly and shall be payable at BPA's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If BPA is unable to render the purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same repayment provisions as shall a final bill.

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the amount unpaid or \$50. In addition, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding

paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

SECTION 9.1. Average Power Factor:

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatt-hours}}{\sqrt{(\text{Kilowatt-hours})^2 + (\text{Reactive Kilovolt-ampere-hours})^2}}$$

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

When deliveries to a purchaser at any point of delivery include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatt-hours and reactive kilovolt-ampere-hours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

SECTION 10.1. Approval of Rates:

Schedules of rates and charges, or modifications thereof, for electric power sold by BPA shall become effective on an interim or final basis after confirmation and approval by the Federal Energy Regulatory Commission in accordance with procedures established by the Commission.

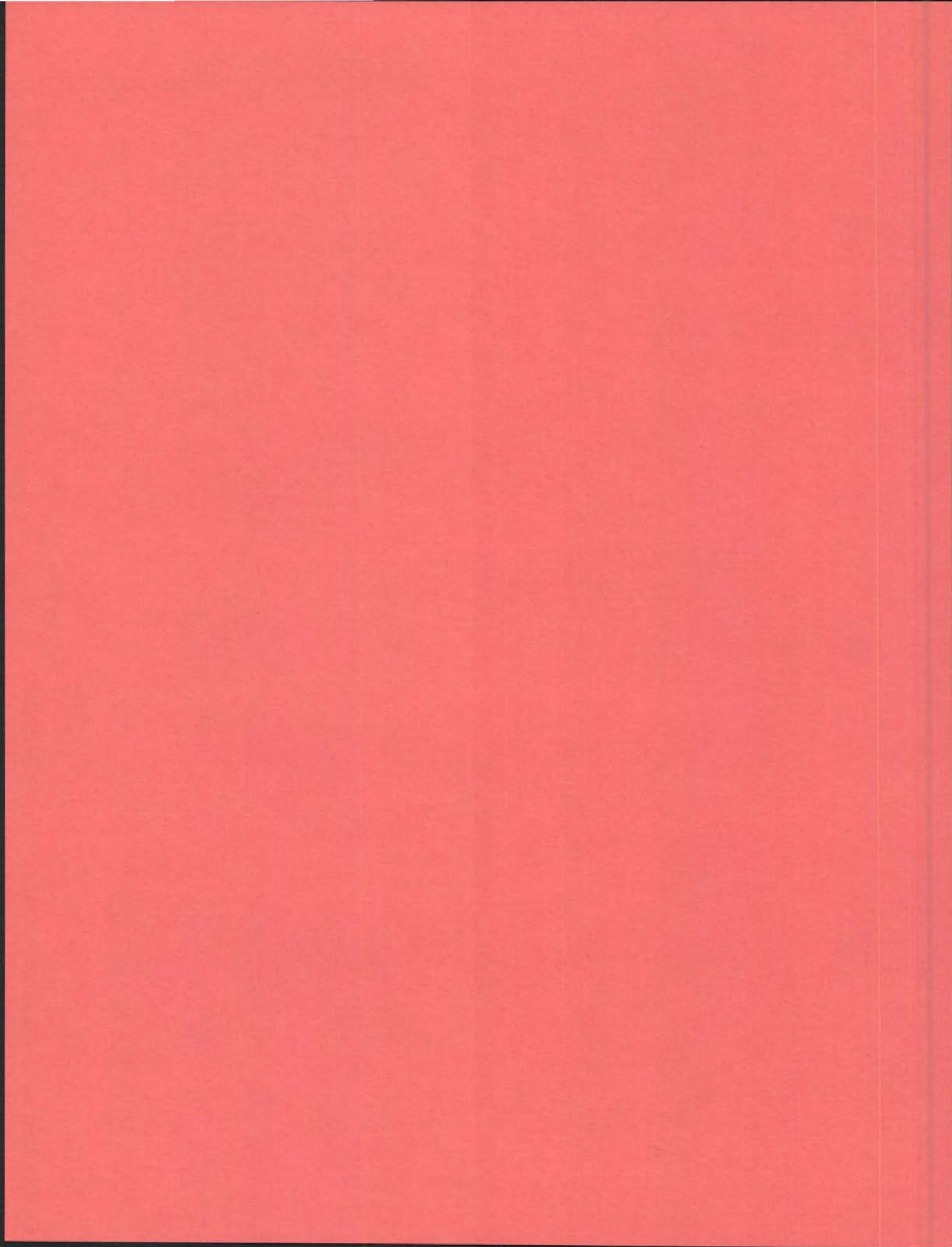
SECTION 11.1. General Provisions:

The Wholesale Rate Schedules and General Rate Schedule Provisions of BPA which are effective October 1, 1982, supersede in their entirety BPA's Wholesale Power Rate Schedule Provisions effective July 1, 1981. Such schedules and provisions shall be applicable to every BPA contract, including contracts executed prior to and contracts executed subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act.



Appendix B

Proposed Rate Schedules



REVISED

WHOLESALE POWER RATE SCHEDULES

AND

GENERAL RATE SCHEDULE PROVISIONS

INITIAL WHOLESALE RATE PROPOSAL 1983

(APPENDIX C TO EXHIBIT BPA-7)

Prepared by
Bonneville Power Administration
U.S. Department of Energy

April 1983

APPENDIX C

BPA'S WHOLESALE POWER RATES AND GENERAL RATE SCHEDULE PROVISIONS

SCHEDULE PF-83

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY:

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

Priority Firm Power may be purchased for resale, direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) may purchase Priority Firm Power pursuant to the Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount of power to be exchanged.

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

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$5.50 (\$5.70) per kilowatt of billing demand,
2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.39 (\$2.48) per kilowatt of billing demand,
3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March: 16.1 (16.7) mills per kilowatthour of billing energy,
2. for the billing months April through August: 12.9 (13.4) mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.
2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

In this section billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), metered requirements purchasers and those priority firm purchasers not covered by sections III.A and III.B (section III.C), and all purchasers of Priority Firm Power during a period of insufficiency (section III.D). If BPA has provided the purchaser with notice of insufficiency, the billing provisions of section III.D shall take precedence over the billing provisions of sections III.A, III.B, and III.C.

A. Computed Requirements Purchasers

Purchasers designated by the Bonneville Power Administration (BPA) as computed requirements purchasers either pursuant to section IV.B.1.b of the General Rate Schedule Provisions or pursuant to power sales contracts executed after December 5, 1980, shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

a. Basic Service

The billing demand for actual and planned computed requirements purchasers shall be the higher of the following billing factors:

- (1) the lower of:
 - (a) the Measured Demand, before adjustment for power factor, or

- (b) the Computed Maximum Requirement which is the larger of the Computed Peak Requirement or the Computed Average Energy Requirement, and

- (2) the lower of:
 - (a) the Computed Peak Requirement, or
 - (b) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

The billing demand for contracted computed requirements purchasers shall be the purchaser's Computed Maximum Requirement.

b. Unauthorized Increase

That portion of any Measured Demand, as adjusted for power factor, which exceeds the Computed Maximum Requirement during any billing month and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy

a. Basic Service

The billing energy for actual and planned computed requirements purchasers shall be the lesser of:

- (1) the Computed Energy Maximum, or
- (2) the sum of:
 - 50 percent of the Measured Energy, and
 - 50 percent of the Computed Energy Maximum.

The billing energy for contracted computed requirements purchasers shall be the purchaser's Computed Energy Maximum.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the Computed Energy Maximum for that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be eighty percent of the energy associated with the utility's residential load for each billing period through June 30, 1984. The percentage shall be increased to 90 percent on July 1, 1984, and to 100 percent on July 1, 1985.

C. Metered Requirements Purchasers and Other Purchasers not covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

a. Basic Service

For metered requirements purchasers the billing demand shall be the Measured Demand as adjusted for power factor.

Other purchasers shall be billed on the Contract Demand, if such demand is specified in the power sales contract. Otherwise the billing demand for such purchasers shall be the Measured Demand as adjusted for power factor.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the amount of firm power the purchaser is

entitled to take pursuant to the power sales contract and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed as unauthorized increase.

2. Billing Energy

a. Basic Service

For metered requirements purchasers the billing energy shall be the Measured Energy.

Other purchasers shall be billed on the Contract Demand multiplied by the number of hours in the billing month, provided a Contract Demand is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take pursuant to the power sales contract during that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed as unauthorized increase.

D. Purchasers of Priority Firm Power during a Period of Insufficiency

In the event of an insufficiency of electric power, all purchasers of Priority Firm Power who are contractually limited to an allocation of capacity and/or energy, as determined by BPA pursuant to the terms of the purchaser's power sales contract, shall be billed as follows:

1. Billing Demand, Given an Allocation of Firm Capacity

a. Basic Service

If there has been an allocation of Firm Capacity, the billing demand shall be the lower of:

- (1) the Measured Demand as adjusted for power factor, or
- (2) the allocation of Firm Capacity, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the allocation of Firm Capacity and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy, Given an Allocation of Firm Energy

a. Basic Service

If there has been an allocation of Firm Energy, the billing energy shall be the lower of:

- (1) the Measured Energy, or
- (2) the allocation of Firm Energy, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the allocation of Firm Energy for that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

3. Billing Factors, Given No Allocation of Firm Capacity and/or No Allocation of Firm Energy

The billing demand or billing energy, if not specifically limited to an allocation pursuant to the purchaser's power sales contract, shall be determined according to the appropriate section, III.A, III.B, or III.C, above.

SECTION IV. ADJUSTMENTS:

A. Power Factor Adjustment

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

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

B. Low Density Discount (LDD)

1. Basic LDD Principles

A predetermined discount shall be applied each month of a calendar year to the charges for power purchased under this rate schedule by eligible purchasers as defined in Section IV.B.2., below. The discount shall be based on the following ratios:

- a. the purchaser's total electric energy requirements during the previous calendar year (including the purchaser's nonfirm sales and sales for resale) divided by the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and
- b. the average number of residential consumers during the previous calendar year divided by the number of pole miles of distribution line at the end of such year.

In calculating these ratios BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

2. Eligibility Criteria

To qualify for a discount, the purchaser must meet all five of the following eligibility criteria:

- a. The purchaser must serve as an electric utility offering power for resale;
- b. the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the BPA region;
- c. the purchaser's kilowatthour to investment ratio (Ratio IV.B.1.a) must be less than 60;
- d. the purchaser's consumers per mile ratio (Ratio IV.B.1.b) must be less than 10; and
- e. the purchaser must qualify for a discount based on the criteria in section IV.B.3, below.

3. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for each are listed below.

a. Three percent

For any purchaser for whom:

- (1) the kilowatthour to investment ratio is equal to or greater than 25 but less than 35, or
- (2) the consumers per mile ratio is equal to or greater than 4 but less than 6.

b. Five percent

For any purchaser for whom:

- (1) the kilowatthour to investment ratio is equal to or greater than 15 but less than 25, or
- (2) the consumers per mile ratio is equal to or greater than 2 but less than 4.

c. Seven percent

For any purchaser for whom:

- (1) the kilowatthour to investment ratio is less than 15, or
- (2) the consumers per mile ratio is less than 2.

C. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule from November 1, 1983, through June 30, 1985.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of 0.213.

D. Supply System Adjustment

The Supply System Adjustment shall be calculated pursuant to section III.C.3 of the General Rate Schedule Provisions and shall be applied to energy purchases made under this rate schedule from July 1, 1984, through June 30, 1985.

For this rate schedule, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = 0.968;
2. BD = 75,919.

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the PF-838 rate is 78 percent FBS and 22 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

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

SCHEDULE IP-83

INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY:

This schedule is available to existing direct-service industrial customers for the contract purchase of Industrial Firm Power on an Operating Demand basis and for Auxiliary Power requested by the purchaser and made available as an Auxiliary Demand by BPA on an intermittent basis. This rate schedule supersedes Schedule IP-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods. Within each rate period there are two sets of charges: one for purchasers during periods when they have not requested service to the first quartile with surplus firm energy load carrying capability (FELCC) and another for purchasers during periods when they have requested such service.

A. When the purchaser has not requested service to the first quartile with surplus FELCC the following rate shall apply:

1. Customer Charge:

- a. for all billing months: \$5.72 (\$5.93) per kilowatt of Operating Demand.

2. Demand Charge:

- a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$4.68 (\$4.85) per kilowatt of billing demand,
- b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.20 (\$2.28) per kilowatt of billing demand,
- c. all other hours: No demand charge.

3. Energy Charge:

- a. for the billing months September through March: 15.0 (15.6) mills per kilowatthour of billing energy,
- b. for the billing months April through August: 12.3 (12.8) mills per kilowatthour of billing energy.

4. Unauthorized Increase Charge:

- a. 83.0 mills per kilowatthour.

B. When the purchaser has requested service to the first quartile with surplus FELCC the following rate shall apply:

1. Customer Charge:

- a. for all billing months: \$7.21 (\$7.48) per kilowatt of Operating Demand.

2. Demand Charge:

- a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$5.50 (\$5.70) per kilowatt of billing demand,
b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.39 (\$2.48) per kilowatt of billing demand,
c. all other hours: No demand charge.

3. Energy Charge:

- a. for the billing months September through March: 16.1 (16.7) mills per kilowatthour of billing energy,
b. for the billing months April through August: 12.9 (13.4) mills per kilowatthour of billing energy.

4. Unauthorized Increase Charge:

- a. 83.0 mills per kilowatthour.

SECTION III. BILLING FACTORS:

A. Billing Demand

1. Basic Service

BPA shall base the billing demand for Industrial Firm Power on the lowest of the following billing factors:

- a. Operating Demand,
b. Curtailed Demand, or
c. Restricted Demand.

Each of the billing factors for demand used in the computation of the power bill shall be adjusted for power factor. Only that portion of the demand which is purchased from BPA shall be considered in the determination of the billing demand.

If the purchaser requests a waiver regarding notice requirements, as specified in the purchaser's power sales contract, for requested

changes in Operating Demand or Curtailed Demand and if BPA does not grant the waiver, the purchaser shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

During any billing month in which there is more than one type of demand (Operating Demand, Curtailed Demand, or Restricted Demand) for Industrial Firm Power basic service, the billing demand for basic service shall be the weighted average of the billing demands for power purchased under this rate schedule for such service during such month.

2. Auxiliary Power

For Auxiliary Power requested by the purchaser and made available by BPA, the billing demand shall be the weighted average of the purchaser's Auxiliary Demands during the billing month, as adjusted for power factor.

3. Curtailements

BPA shall charge the purchaser for curtailments in accordance with the provisions of section 9(c) of the power sales contract.

4. Unauthorized Increase

If the Measured Demand during the hours 7 a.m. - 10 p.m. on any day Monday through Saturday exceeds the sum of:

- a. the billing demand (as specified in section III.A.1) during that hour before adjustment for power factor,
b. the Auxiliary Demand during that hour before adjustment for power factor, and
c. any applicable demands which the purchaser acquires through other contracts for such hour,

the difference may be billed:

- a. as unauthorized increase, or
b. as additional billing demand under this rate schedule.

BPA shall make the determination as to how the unauthorized increase shall be billed.

5. Transitional Service

If the purchaser requests billing on a Measured Demand basis pursuant to section 4 of the power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the weighted average of the daily Measured Demands as adjusted for power factor. However, at no time during the period of restoration, as

defined in section 4(e) of the power sales contract, shall the daily demand be lower than any previous such demand during such period. Should the Measured Demand for any day during the period of restoration be lower than the daily demand for the previous day, the previous day's daily demand shall be used as the daily demand for such day.

B. Billing Energy

The billing energy 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. ADJUSTMENTS:

A. Value of Reserves

A monthly billing credit for the value of the reserves provided by purchasers of Industrial Firm Power shall be:

1. \$0.25 (\$0.26) per kilowatt of billing demand and
2. 1.7 (1.8) mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under sections III.A.1 and III.A.2 of this rate schedule. No value of reserves credit shall be applied to that portion of the purchaser's demand subject to curtailment charges under section III.A.3 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.A.4, above.

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 this rate schedule from November 1, 1983, through June 30, 1985.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of 0.822.

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the IP-838 rate is 100 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

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

SCHEDULE IH-83
SPECIAL INDUSTRIAL RATE

SECTION I. AVAILABILITY:

This schedule is available for the Hanna Nickel Smelting Company's contract purchase of a special class of Industrial Power on an Operating Demand basis and for Auxiliary Power requested by the purchaser and made available as an Auxiliary Demand by BPA on an intermittent basis. This rate schedule is made available pursuant to section 7(d)(2) of the Pacific Northwest Electric Power Planning and Conservation Act. This schedule supersedes Schedule SI-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$5.50 (\$5.70) per kilowatt of billing demand,
2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$ 2.39 (\$2.48) per kilowatt of billing demand,
3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March:
16.1 (16.7) mills per kilowatthour of billing energy,
2. for the billing months April through August:
12.9 (13.4) mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.

SECTION III. BILLING FACTORS:

A. Billing Demand

1. Basic Service

BPA shall base the billing demand for this special class of Industrial Power on the lowest of the following billing factors:

- a. Operating Demand,
- b. Curtailed Demand, or
- c. Restricted Demand.

Each of the billing factors for demand used in the computation of the power bill shall be adjusted for power factor. Only that portion of the demand which is purchased from BPA shall be considered in the determination of the billing demand.

If the purchaser requests a waiver regarding notice requirements, as specified in the purchaser's power sales contract, for requested changes in Operating Demand or Curtailed Demand and if BPA does not grant the waiver, the purchaser shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

During any billing month in which there is more than one type of demand (Operating Demand, Curtailed Demand, or Restricted Demand) for basic service from this special class of Industrial Power, the billing demand for basic service shall be the weighted average of the billing demands for power purchased under this rate schedule for such service during such month.

2. Auxiliary Power

For Auxiliary Power requested by the purchaser and made available by BPA, the billing demand shall be the weighted average of the purchaser's Auxiliary Demands during the billing month, as adjusted for power factor.

3. Curtailments

BPA shall charge the purchaser for curtailments in accordance with the provisions of section 9(c) of the power sales contract.

4. Unauthorized Increase

If the Measured Demand during the hours 7 a.m. - 10 p.m. on any day Monday through Saturday exceeds the sum of:

- a. the billing demand (as specified in section III.A.1) during that hour before adjustment for power factor,
- b. the Auxiliary Demand during that hour before adjustment for power factor, and
- c. any applicable scheduled demands which the purchaser acquires through other contracts for such hour,

the difference may be billed:

- a. as unauthorized increase, or
- b. as additional billing demand under this rate schedule.

BPA shall make the determination as to how the unauthorized increase shall be billed.

5. Transitional Service

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 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. ADJUSTMENTS:

A. Value of Reserves

An adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power shall be:

1. \$0.25 (\$0.26) per kilowatt of billing demand and
2. 1.7 (1.8) mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under sections III.A.1 and III.A.2 of this rate schedule. No value of reserves credit shall be applied to that portion of the purchaser's demand subject to curtailment charges under section III.A.3 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.A.4, above.

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.

SECTION V. RESOURCE COST CONTRIBUTION:

The IH-838 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

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

SCHEDULE 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 for supply during a contract year of 12 months or during a contract season of 5 months, June 1 through October 31. This schedule supersedes Schedule CF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Contract Year Service

\$44.16 (\$45.84) per kilowatt per year of Contract Demand, billed monthly at the rate of \$3.68 (\$3.82) per kilowatt of Contract Demand.

B. Contract Season Service

\$11.95 (\$12.40) per kilowatt per season of Contract Demand, billed monthly during the contract season at the rate of \$2.39 (\$2.48) per kilowatt of Contract Demand.

C. Intertie Service

The monthly capacity rate specified in subsections A.1 and A.2, above, shall be increased by \$0.51 (\$0.53) per kilowatt for capacity made available at the Oregon-California or the Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

D. Extended Peaking Surcharge

The monthly capacity rate specified in subsections A, B, and, if applicable, C, above, shall be increased by \$0.043 per kilowatt of billing demand for each hour that the purchaser's monthly demand duration exceeds 9 hours. The charge shall be prorated for each portion of an hour of extended peaking supplied to the purchaser. The purchaser's demand duration for the month shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the on-peak day (Monday through Saturday) of maximum kilowatthour use during those hours, by

2. the purchaser's Contract Demand for such month.

The additional charge described above shall not be applied during periods when BPA is offering Nonfirm Energy for sale.

SECTION III. BILLING FACTORS:

The billing demand shall be the Contract Demand.

SECTION IV. SPECIAL PROVISION:

Contracts for the purchase of Firm Capacity under this schedule shall include provisions for the purchaser to replace the energy accompanying the delivery of such capacity.

SECTION V. ADJUSTMENTS:

A. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule from November 1, 1983, through June 30, 1985.

For contract year service, the variable EC in the Exchange Adjustment calculation shall have a value of 0.338.

For contract season service, the variable EC in the Exchange Adjustment calculation shall have a value of 0.240.

B. Supply System Adjustment

The Supply System Adjustment shall be calculated pursuant to section III.C.3 of the General Rate Schedule Provisions and shall be applied to energy purchases made under this rate schedule from July 1, 1984, through June 30, 1985.

For contract year service, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = 0.011;
2. BD = 14,124.

For contract season service, the variables SS and BD in the Supply System calculation shall have the following values:

1. SS = 0.001;
2. BD = 3,000.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the CF-83B rate is 70 percent FBS and 30 percent Exchange for contract year service, and 75 percent FBS and 25 percent Exchange for contract season service.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS

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

SCHEDULE CE-83

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY:

This schedule is available for the purchase of capacity:

- A. when an emergency exists on the purchaser's system, or
- B. when the purchaser wishes to displace higher cost firm capacity resources which are otherwise available to meet the purchaser's load

provided the purchaser requests such capacity and BPA has capacity available for such purpose.

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

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Demand Charge

\$1.11 (\$1.15) per kilowatt of demand per calendar week or portion thereof.

B. Intertie Charge

The demand charge specified above shall be increased by \$0.13 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS:

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

SECTION IV. BILLING PERIOD:

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION:

Energy delivered with such capacity shall be returned to WPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the CE-83 rate is 70 percent FBS and 30 percent Exchange.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

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

SCHEDULE NR-83

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY:

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

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

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

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

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Demand Charge:

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$5.50 (\$5.70) per kilowatt of billing demand,
2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.39 (\$2.48) per kilowatt of billing demand,
3. all other hours: No demand charge.

B. Energy Charge:

1. for the billing months September through March: 25.5 (26.4) mills per kilowatthour of billing energy,
2. for the billing months April through August: 21.5 (22.3) mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge:

1. 83.0 mills per kilowatthour.
2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

In this section billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), metered requirements purchasers and those New Resource Firm Power purchasers not covered by section III.A (section III.B), and purchasers of New Resource Firm Power during a period of insufficiency (section III.C). If BPA has provided the purchaser with notice of insufficiency, the billing provisions of section III.C shall take precedence over the billing provisions of sections III.A and III.B.

A. Computed Requirements Purchasers

Purchasers designated by the Bonneville Power Administration (BPA) as computed requirements purchasers pursuant to power sales contracts executed after December 5, 1980, shall be billed in accordance with the provisions of this section.

1. Billing Demand

a. Basic Service

The billing demand for actual and planned computed requirements purchasers shall be the higher of the following billing factors:

- (1) the lower of:
 - (a) the Measured Demand, before adjustment for power factor, or
 - (b) the Computed Maximum Requirement which is the larger of the Computed Peak Requirement or the Computed Average Energy Requirement, and
- (2) the lower of:
 - (a) the Computed Peak Requirement, or
 - (b) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

The billing demand for contracted computed requirements purchasers shall be the Computed Maximum Requirement.

b. Unauthorized Increase

That portion of any Measured Demand, as adjusted for power factor, which exceeds the Computed Maximum Requirement during any billing month and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy

a. Basic Service

The billing energy for actual and planned computed requirements purchasers shall be the lesser of:

- (1) the Computed Energy Maximum, or
- (2) the sum of:
 - 32 percent of the Measured Energy, and
 - 68 percent of the Computed Energy Maximum.

The billing energy for contracted computed requirements purchasers shall be the Computed Energy Maximum.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the Computed Energy Maximum for that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or

- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Metered Requirements Purchasers and Other Purchasers not covered by Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

a. Basic Service

For metered requirements purchasers the billing demand shall be the Measured Demand as adjusted for power factor.

Other purchasers shall be billed on the Contract Demand if specified in the power sales contract. Otherwise the billing demand for such purchasers shall be the Measured Demand as adjusted for power factor.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the amount of firm power the purchaser is entitled to take pursuant to the power sales contract and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed as unauthorized increase.

2. Billing Energy

a. Basic Service

For metered requirements purchasers the billing energy shall be the Measured Energy.

Other purchasers shall be billed on the Contract Demand multiplied by the number of hours in the billing month, provided a Contract Demand is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take

pursuant to the power sales contract during that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed as unauthorized increase.

C. Purchasers of New Resource Firm Power during a Period of Insufficiency

In the event of an insufficiency of electric power, all purchasers of New Resource Firm Power who are contractually limited to an allocation of capacity and/or energy, as determined by BPA pursuant to the terms of the purchaser's power sales contract, shall be billed as follows:

1. Billing Demand, Given an Allocation of Firm Capacity

a. Basic Service

If there has been an allocation of firm capacity, the billing demand shall be the lower of:

- (1) the Measured Demand as adjusted for power factor, or
- (2) the allocation of firm capacity, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

That portion of any Measured Demand, before adjustment for power factor, which exceeds the allocation of firm capacity and which cannot be assigned:

- (1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

2. Billing Energy, Given an Allocation of Firm Energy

a. Basic Service

If there has been an allocation of firm energy, the billing energy shall be the lower of:

- (1) the Measured Energy, or
- (2) the allocation of firm energy, determined pursuant to the purchaser's power sales contract.

b. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the allocation of firm energy for that month and which cannot be assigned:

- (1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- (2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

- (1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- (2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

3. Billing Factors, Given No Allocation of Firm Capacity and/or No Allocation of Firm Energy

The billing demand or billing energy, if not specifically limited to an allocation pursuant to the purchaser's power sales contract, shall be determined according to the appropriate section, III.A or III.B, above.

SECTION V. ADJUSTMENTS:

A. Power Factor Adjustment

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

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

B. Exchange Adjustment

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

purchases under this rate schedule from November 1, 1983, through June 30, 1985.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of 0.898.

SECTION VII. RESOURCE COST CONTRIBUTION:

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

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VIII. GENERAL PROVISIONS:

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

SCHEDULE SP-83

SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Surplus Firm Power to be used either for resale or direct consumption. Surplus Firm Power may be sold to entities inside and outside the Pacific Northwest as well as outside the United States. However, this rate schedule shall not apply to contracts for which rates have been negotiated pursuant to section 7(1) of the Regional Act. In addition, this schedule is not available to any direct-service industrial purchaser who buys power either under rate Schedule IP-83 or Schedule IH-83. Schedule SP-83 supersedes Schedule SP-1 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

The rate for Surplus Firm Power shall be mutually agreed upon and contractually specified by the parties prior to delivery of the power. A contract having an effective term of less than one year and terminating on or before June 30, 1985, may reference any of the four rates described below (Thermal Resource Rate, Exchange Resource Rate, Purchased Power Rate, or Contract Rate). A contract having an effective term of more than one year or terminating after June 30, 1985, shall reference the Contract Rate.

A. Thermal Resource Rate

A Surplus Firm Power rate based on the cost of thermal resources shall be set at a level which will recover BPA's cost of generating and transmitting power from one or more Federal system thermal resources to the contractually specified point of delivery. A Thermal Resource Rate shall include all the variable costs and up to 100 percent of the fixed costs associated with generating and transmitting such thermal power.

The following variable costs, if applicable, shall be included in the determination of a Thermal Resource Rate: (a) total fuel costs; (b) incremental costs of labor and supplies required for operation and maintenance of the thermal plant(s) providing such power; (c) incremental administrative and general expenses; (d) taxes; (e) transmission network losses (to be priced at the incremental cost of the fuel required to generate the lost power); and (f) any other related costs associated with production and transmission of such thermal power.

The fixed costs associated with the generation and transmission of such thermal power shall include, if applicable: (a) debt service; (b) capital additions; (c) taxes; (d) fixed administrative and general expenses; (e) fixed operation and maintenance expenses; (f) insurance for the facilities used in the production and transmission of this thermal power; and (g) any other fixed costs associated with the generation and transmission of such thermal power.

Prior to delivery of this thermal power, BPA shall determine what portion of the fixed costs listed above shall be included in the rate.

B. Exchange Resource Rate

A Surplus Firm Power rate based on the cost of exchange resources shall contractually specify use of one of the following costs as the basis of the charge:

1. the average cost of exchange resources of one or more utilities participating in the residential exchange, or
2. the average cost of all exchange resources.

The forecast exchange resource cost included in the determination of the 1983 Wholesale Power Rates shall be used in the calculation of this rate.

The rate shall also include identifiable delivery costs (such as losses and transmission).

C. Purchased Power Rate

A Surplus Firm Power rate based on the cost of purchased power shall be the sum of:

1. the total costs to BPA of the specified purchase, and
2. any identifiable costs (such as losses and transmission costs) directly associated with such energy purchase and redelivery.

D. Contract Rate

The Contract Rate includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

For contracts which refer to the Contract Rate in this rate schedule in determining the rate for Surplus Firm Power or Surplus Firm Energy, the following rate shall apply:

1. Demand Charge

- a. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$5.50 (\$5.70) per kilowatt of billing demand,
- b. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.39 (\$2.48) per kilowatt of billing demand,
- c. All other hours: No demand charge.

2. Energy Charge:

- a. for the billing months September through March: 25.2 (26.1) mills per kilowatthour of billing energy,
- b. for the billing months April through August: 21.1 (21.9) mills per kilowatthour of billing energy.

3. Escalation Factor:

The SP-83 Contract Rate shall be subject to change each July 1, beginning July 1, 1985. The change in the SP-83 Contract Rate shall be determined in the manner described below for all contracts which extend beyond June 30, 1985. The effective rate for each rate component of the Contract Rate shall be equal to:

$$\text{Rate}_n = \text{Rate}_{n-1} * (1 + \text{ARG}_{n-1})$$

where:

- Rate_n = the rate in the operating year (July 1 - June 30) for which the SP-83 Contract Rate is being calculated; and
- Rate_{n-1} = the rate for each component (winter demand, summer demand, winter energy, summer energy) of the SP-83 Contract Rate in the previous year (year n-1).
- ARG_{n-1} = the weighted average annual rate of growth in the average cost of exchange resources in year n-1 as calculated on July 1 in year n. The average cost of exchange resources shall be based on the average system costs of C. P. National Corporation, Idaho Power Company, Pacific Power & Light Company, Portland General Electric Company, and Utah Power & Light Company. If any of the five utilities elect to equalize rates in year n-1 pursuant to Section 10 of the Residential Purchase and Sale Agreement, the calculation of ARG shall not reflect the average system cost of such electing utility.

SECTION III. BILLING FACTORS:

The billing demand and billing energy for power purchased under this rate schedule shall be the Measured Demand and the Measured Energy unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS:

A. Power Factor Adjustment

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

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

B. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule from November 1, 1983, through June 30, 1985.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of 0.885.

SECTION V. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the SP-83 rate is 97 percent Exchange and 3 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

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

SCHEDULE SE-83
SURPLUS FIRM ENERGY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Surplus Firm Energy to be used either for resale or direct consumption. Surplus Firm Energy may be sold to entities inside and outside the Pacific Northwest as well as outside the United States. However, this rate schedule shall not apply to contracts for which rates have been negotiated pursuant to section 7(1) of the Regional Act. In addition, this schedule is not available to any direct-service industrial purchaser who buys power either under rate Schedule IP-83 or Schedule IH-83. Schedule SE-83 supersedes Schedule SE-1 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. The rate for Surplus Firm Energy shall be:

28.5 (29.6) mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS:

The billing energy shall be determined as provided in the purchaser's power sales contract. If BPA does not have a power sales contract in force with a purchaser, the billing energy shall be the Measured Energy.

SECTION IV. DELIVERY:

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

SECTION V. ADJUSTMENTS:

A. Power Factor

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate

Schedule Provisions. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

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

B. Exchange Adjustment

The Exchange Adjustment shall be calculated pursuant to section III.C.2 of the General Rate Schedule Provisions and shall be applied to all power purchases under this rate schedule from November 1, 1983, through June 30, 1985.

For this rate schedule, the variable EC in the Exchange Adjustment calculation shall have a value of 0.885.

SECTION VI. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the SE-83B rate is 97 percent Exchange and 3 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VII. GENERAL PROVISIONS:

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

SCHEDULE NF-83

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY:

This schedule is available for the contract purchase of Nonfirm Energy to be used both inside and outside the Pacific Northwest as well as outside the United States. This schedule also applies to energy delivered for emergency use under the conditions set forth in Section V.B of the General Rate Schedule Provisions. This rate schedule is not available for the purchase of energy which BPA has a firm obligation to supply, nor is this schedule applicable to contracts for which rates have been negotiated pursuant to section 7(1) of the Regional Act. This schedule supersedes Schedule NF-2 which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Market Rates

The price per kilowatthour of billing energy shall be set according to the following four conditions. More than one condition may apply at any given time.

1. Standard Rate

The rate shall be 20.1 (20.8) mills per kilowatthour.

This rate shall apply when the Federal Columbia River Power System (FCRPS) hydroelectric plants are not spilling or are not forecast to spill due to more energy being available for sale than can be sold at the Standard Rate due to market conditions.

At the time that BPA offers Nonfirm Energy under this rate, BPA shall indicate the maximum amount of energy available for the next day or days over which nonfirm is normally prescheduled in the Pacific Northwest and the maximum hourly available amounts of such energy.

BPA shall offer 50 percent of the maximum daily amount of energy and 50 percent of each maximum hourly amount of energy on a guaranteed delivery basis. At the time that the purchaser arranges schedules of such energy, it shall indicate the amount it wishes to schedule on a guaranteed delivery basis and the amount it wishes to schedule on a nonguaranteed delivery basis. The energy which BPA makes available

for delivery on the same day that scheduling arrangements are made is not subject to the guaranteed delivery provision.

Scheduling of sales under the Standard Rate shall be consistent with the scheduling provisions of the purchaser's power sales agreement with BPA. Scheduled amounts of guaranteed Nonfirm Energy may not be changed except:

- when BPA and the Purchaser mutually agree to increase or decrease the scheduled amounts, or
- when BPA must reduce Nonfirm Energy deliveries in order to serve firm loads because of unexpected generation loss in the Pacific Northwest.

2. Spill Rate

This rate shall apply when one or more Federal Columbia River Power System (FCRPS) hydroelectric plants are spilling or are forecast to spill due to more FCRPS energy being available than can be sold at the Standard Rate. The rate shall be 12.5 (13.0) mills per kilowatthour.

3. Displacement Rate

When more energy is available on the FCRPS than can be sold at the Spill Rate, additional energy may be made available under the Displacement Rate. For participants in the Western Systems Coordinating Council (WSCC) Energy Broker System, such sales shall be made through the WSCC Broker Identified Energy Agreement under the EB-83 Energy Broker Rate.

The rate shall be the Spill Rate whenever the Buy Price is greater than or equal to the Spill Rate plus 2.0 mills per kilowatthour. Otherwise the rate shall be:

$$\frac{\text{Buy Price} + \text{BPA Sell Price}}{2}$$

where:

- the Buy Price is the estimated decremental expense per kilowatthour which would otherwise have been incurred by the purchaser in generating or acquiring power from alternative resources, and
- the BPA Sell Price is the higher of:
 - 1.0 mill per kilowatthour, or
 - the estimated incremental or equivalent expense per kilowatthour which BPA will incur in supplying energy to the buyer during that hour. BPA shall make the determination as to which resources are available to supply power to the purchaser during that hour.

4. Incremental Rate

The Incremental Rate shall be applied to sales of power:

- a. which is produced or purchased concurrently with the nonfirm sale,
- b. which BPA may at its option not produce or purchase, and
- c. which has an Incremental Cost greater than 18.1 (18.8) mills per kilowatthour.

The rate shall be equal to the Incremental Cost of that power plus 2.0 mills per kilowatthour.

where:

Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) which BPA would not have incurred if it had chosen not to produce or purchase the power being sold under this rate.

B. Contract Rate

For contracts that refer to this schedule to determine the value of energy, the rate is 14.6 (15.1) mills per kilowatthour.

SECTION III. DELIVERY:

BPA shall determine the availability of energy to be provided under this rate schedule and the associated rate of delivery.

SECTION IV. RESOURCE COST CONTRIBUTION:

The approximate cost contribution of different resource categories to the NF-83B Standard Rate is 99.6 percent FBS and 0.4 percent New Resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION V. GENERAL PROVISIONS:

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

SCHEDULE EB-83

ENERGY BROKER RATE

SECTION I. AVAILABILITY:

This rate schedule may be applied to both sales and purchases of nonfirm energy among those participants in the Western Systems Coordinating Council (WSCC) Energy Broker System between whom agreements for energy transmission have been transacted. This schedule supersedes Schedule EB-1, which went into effect on an interim basis on October 1, 1982.

SECTION II. RATE:

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

$$EB-83 = \frac{BP + SP}{2}$$

where: EB-83 = Energy Broker Rate
BP = Quoted Buy Price
SP = Quoted Sell Price

The Energy Broker will identify potential transactions when the Sell Price is at least 4.0 mills per kilowatthour less than the Buy Price. The final transaction rate for brokered Nonfirm Energy will be based on splitting the difference between the quoted Buy and Sell Prices, with the settlement for wheeling charges and energy losses defined in accordance with Exhibit A of the WSCC Broker Transmission Service Agreement.

When a transaction involving BPA takes place on the Energy Broker System, the BPA Buy Price and BPA Sell Price, respectively, shall be defined as follows:

- A. The BPA Buy Price is the estimated decremental or equivalent expense per kilowatthour which would otherwise have been incurred by BPA in generating or purchasing power from alternative sources in lieu of broker energy scheduled for delivery to BPA during that hour.
- B. The BPA Sell Price is the estimated incremental or equivalent expense per kilowatthour which would be incurred by BPA in supplying broker energy scheduled for delivery during such hour to the buyer from resources which are available to supply power during that hour as determined by BPA.

SECTION III. DELIVERY:

BPA shall determine the availability of energy to be provided under this rate schedule and the associated rate of delivery.

SECTION IV. RESOURCE COST CONTRIBUTION:

The cost contribution of different resource categories to the EB-83 rate is based upon the specific resource(s) offered during the scheduled time of sale.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour after displacement by BPA's available secondary energy.

SECTION V. GENERAL PROVISIONS:

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

SCHEDULE RP-83

RESERVE POWER RATE

SECTION I. AVAILABILITY:

This schedule is available for the purchase of:

- A. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract,
- B. power for which BPA determines no other rate schedule is applicable, and/or
- C. power to serve a purchaser's firm power loads in circumstances where BPA does not have a power sales contract in force with such purchaser and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States.

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

SECTION II. RATE:

This rate schedule includes charges for two rate periods. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues until this rate schedule is superseded. The charge for Period B is shown in parentheses immediately following the charge for Period A. If only one rate appears, the given rate is effective for both rate periods.

A. Demand Charge

1. for the billing months December through April, Monday through Saturday, 7 a.m. through 10 p.m.: \$9.10 (\$9.44) per kilowatt of billing demand,
2. for the billing months May through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.33 (\$2.42) per kilowatt of billing demand,
3. all other hours: No demand charge.

B. Energy Charge

33.1 (34.3) mills per kilowatthour of billing energy.

C. Unauthorized Increase Charge

1. 83.0 mills per kilowatthour.
2. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to the Billing Demand subsections of section III of this rate schedule. That amount which BPA actually treats as unauthorized increase pursuant to the Billing Demand subsections of section III shall be excluded from the total of the integrated or scheduled demands used to determine the amount which may be considered an unauthorized increase under the Billing Energy subsections of section III.

SECTION III. BILLING FACTORS:

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

A. Billing Demand

1. Basic Service

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

2. Unauthorized Increase

That portion of any Measured Demand, as adjusted for power factor, which exceeds the Contract Demand during any billing month and which cannot be assigned:

- a. to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser, or
- b. to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour

shall be billed:

- a. in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- b. as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

B. Billing Energy

1. Basic Service

If applicable, the billing energy shall be the Contract Demand in kilowatthours as specified in the power sales contract. Otherwise the billing energy shall be the Measured Energy for the month.

2. Unauthorized Increase

The amount of Measured Energy during a billing month which exceeds the amount which the purchaser is entitled to take pursuant to the power sales contract during that month and which cannot be assigned:

- a. to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser, or
- b. to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month

shall be billed:

- a. in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract, or
- b. as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

SECTION IV. POWER FACTOR ADJUSTMENT:

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

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

SECTION V. RESOURCE COST CONTRIBUTION:

The RP-83 rate is not based on the cost of resources.

The forecasted average cost of resources available to the Administrator under average water conditions is 20.2 mills per kilowatthour.

The forecasted cost of resources to meet load growth is 29.3 mills per kilowatthour.

SECTION VI. GENERAL PROVISIONS:

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

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS

- I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions
 - A. Approval of Rates
 - B. General Provisions
 - C. Reorganization of the Wholesale Power Rate Schedules and General Rate Schedule Provisions
 1. Reorganization of the Wholesale Power Rate Schedules
 2. Reorganization of the General Rate Schedule Provisions
- II. Types of BPA Service
 - A. Priority Firm Power
 - B. New Resource Firm Power
 - C. Industrial Firm Power
 - D. Auxiliary Power
 - E. Firm Capacity
 - F. Surplus Firm Power
 - G. Surplus Firm Energy
 - H. Nonfirm Energy
 - I. Energy Broker Energy
 - J. Reserve Power
- III. Billing Factors and Billing Adjustments
 - A. Billing Factors for Demand
 1. Measured Demand
 2. Contract Demand
 3. Auxiliary Demand
 4. Computed Peak Requirement
 5. Computed Average Energy Requirement
 6. Computed Maximum Requirement
 7. Operating Demand
 8. Curtailed Demand
 9. Restricted Demand
 - B. Billing Factors for Energy
 1. Measured Energy
 2. Computed Energy Maximum
 - C. Billing Adjustments
 1. Power Factor Adjustment
 2. Exchange Adjustment Clause
 3. Supply System Adjustment Clause
- IV. Other Definitions
 - A. Restriction of Deliveries
 - B. Computed Requirements Purchasers
 1. Designation as a Computed Requirements Purchaser
 2. Purpose of the Computed Requirements Designation
 3. Definitions and Terms Relating to Computed Requirements Purchasers with Power Sales Contracts Executed Prior to December 5, 1980
 - a. General Principles
 - b. Determination of Assured Capability

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS (Cont'd)

- V. Application of Rates Under Special Circumstances
 - A. Temporary Curtailment of Contract Demand
 - B. Energy Supplied for Emergency Use
 - C. Application of Rates During Initial Operation Period
 - D. Construction, Test and Start-up, and Station Service
- VI. Billing Information
 - A. Billing for Purchasers with More than One Point of Delivery
 - B. Determination of Estimated Billing Data
 - C. Billing Month
 - D. Payment of Bills

GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS:

A. Approval of Rates

Schedules of rates and charges for electric power sold by BPA or modifications to those schedules shall become effective on an interim or final basis after confirmation and approval by the Federal Energy Regulatory Commission in accordance with procedures established by the Commission.

B. General Provisions

BPA's Wholesale Power Rate Schedules and associated General Rate Schedule Provisions (GRSP's) which are effective November 1, 1983, supersede in their entirety BPA's Wholesale Power Rate Schedules and GRSP's effective October 1, 1982. The revised schedules and provisions shall be applicable to every BPA contract, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act).

C. Reorganization of the Wholesale Power Rates and General Rate Schedule Provisions

1. Reorganization of the Wholesale Power Rates

All references to Section 4 of the rate schedules for Industrial Power shall be deemed to refer to the section in such schedules entitled "Billing Factors."

2. Reorganization of the General Rate Schedule Provisions (GRSP's)

All references to sections in those GRSP's which were in effect prior to November 1, 1983, are deemed to refer to the section in these revised GRSP's indicated in the listing below.

Section Title	Old GRSP's Section #	New GRSP's Section #
Priority and New Resource Firm Power (Now divided into two sections)	1.1	II.A
Modified Firm Power	1.2	II.B
Firm Capacity	1.3	N/A
Industrial Firm Power	1.4	II.E
Authorized Increase	1.5	II.C
Firm Energy	1.6	N/A
Contract Demand	2.1	III.A.2
Auxiliary Demand	2.2	III.A.3

Section Title	Old GRSP's Section #	New GRSP's Section #
Measured Demand	2.3	III.A.1
Peak Computed Demand and Energy Computed Demand (Now divided into 3 sections: Computed Peak Requirement, Computed Average Energy Requirement, and Computed Maximum Requirement)	2.4	III.A.4 III.A.5 III.A.6
Restricted Demand	2.5	III.A.9
Curtailed Demand	2.6	III.A.8
Temporary Curtailment of Contract Demand	3.1	V.A
Energy Supplied for Emergency Use	4.1	V.B
Application of Rates During Initial Operation Period	5.1	V.C
Billing	6.1	VI.A
Determination of Estimated Billing Data	6.2	VI.B
Billing Month	7.1	VI.C
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SECTION II. TYPES OF BPA SERVICE:

A. Priority Firm Power

Priority Firm Power is electric power which BPA will make continuously available for resale, direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies.

Construction, test and start-up, and station service are defined in section V.D of these GRSP's.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) may purchase Priority Firm Power pursuant to the Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount of power to be exchanged.

Power purchased under the Priority Firm Power Rate Schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSP's (section IV.A). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSP's.

Any increase in energy consumption of a load as defined in:

1. section 3.(13) of the Regional Act, or
2. section 8 of any BPA power sales contract executed after December 5, 1980,

shall be served under the New Resource Firm Power Rate.

B. New Resource Firm Power

New Resource Firm Power is electric power which BPA will make continuously available:

1. for any new large single load as defined in section 3.(13) of the Regional Act, and as described in section 8 of any BPA power sales contract executed after December 5, 1980,
2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and/or
3. for construction, test and start-up, and station service for facilities owned and/or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSP's (section IV.A). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSP's.

C. Industrial Firm Power

Industrial Firm Power is electric power which BPA will make continuously available to a direct-service industrial purchaser on a Contract Demand basis subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and
2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

When such a restriction is made necessary, BPA shall restrict such purchaser's Operating Demand for Industrial Firm Power to the extent necessary to prevent, if possible, and otherwise to minimize restriction of Priority Firm and New Resource Firm Power.

D. Auxiliary Power

Auxiliary Power is that power which a direct service industrial purchaser requests and which BPA agrees to make available to serve that portion of the purchaser's load which is in excess of the purchaser's Operating Demand for Industrial Firm Power.

E. Firm Capacity

Firm Capacity means capacity which BPA assures a purchaser will be available in amounts and during the periods specified in the contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

F. Surplus Firm Power

Surplus Firm Power is power which BPA assures a purchaser will be available during the period or periods specified in the contract. Such power may be purchased for resale or direct consumption by entities both inside and outside the United States. Surplus Firm Power may, however, be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

G. Surplus Firm Energy

Surplus Firm Energy is energy which BPA assures a purchaser will be available during the period or periods specified in the contract. Such energy may be purchased for resale or direct consumption by entities both inside and outside the United States. Surplus Firm Energy may, however, be restricted pursuant to the Restriction of Deliveries section of these GRSP's (section IV.A).

H. Nonfirm Energy

Nonfirm Energy is energy which BPA supplies or makes available to a purchaser under an arrangement which does not have the guaranteed continuous availability feature of firm power. However, Nonfirm Energy which has been purchased under the guarantee provision in the Nonfirm Energy Rate Schedule shall be provided to the purchaser in accordance with the provisions of that schedule. Nonfirm Energy may not be used to serve any load which BPA has a firm obligation to supply.

I. Energy Broker Energy

Energy Broker Energy, as used in BPA's EB-83 rate schedule, is Nonfirm Energy that:

1. BPA purchases from the Western Systems Coordinating Council (WSCC) Energy Broker System under the Energy Broker Rate Schedule, or
2. BPA makes available to the WSCC for sale to WSCC participants. Power that BPA sells to WSCC participants is subject to the Restriction of Deliveries section of these GRSP's (section IV.A).

J. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. to meet the purchaser's unanticipated load growth,
2. to provide service when no other type of power is deemed applicable, and/or

3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSP's (section IV.A).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. BILLING FACTORS FOR DEMAND

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section unless the terms of a power sales contract executed after December 5, 1980, provide otherwise. Measured Demand shall be that portion of the metered and/or scheduled demand which is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand and/or the scheduled demand, as hereinafter defined. The Measured Demand for each point of delivery shall be determined either on a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

Metered Demand:

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

- a. at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,
- b. during each time period specified in the applicable rate schedule, and
- c. during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.B herein. In determining the metered demand, BPA will exclude any abnormal integrated demands due to or resulting from:

- a. emergencies or breakdowns on, or maintenance of, the Federal system facilities, and
- b. emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

Scheduled Demand:

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

- a. to each system for which scheduled demand is the basis for determination of the Measured Demand,
- b. during each time period specified in the applicable rate schedule, and
- c. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Contract Demand

The Contract Demand shall be the maximum number of kilowatts or kilowatthours that the purchaser (utility, direct service industrial customer, or other entity) agrees to purchase and BPA agrees to make available. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries.

3. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a direct service industrial purchaser requests and that BPA agrees to make available to serve the purchaser's load during the period specified in the purchaser's request. The purchaser may request up to three levels of Auxiliary Demand during a billing month. If BPA agrees to such request but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power shall be deemed to be the Auxiliary Demand for such period. Auxiliary Power may be curtailed by the purchaser in accordance with the provisions of section 9(a) of the purchaser's power sales contract.

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements under power sales contracts executed after December 5, 1980, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

- a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers,
- b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers, and
- c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

For computed requirements purchasers with power sales contracts executed prior to December 5, 1980, the purchaser's Computed Peak Requirement for each billing month shall be the largest amount during such month by which the purchaser's actual hourly system demand, excluding any loads otherwise

provided for in the contract, exceeds its assured peaking capability for such month, as determined pursuant to section IV.B.3 of these General Rate Schedule Provisions.

5. Computed Average Energy Requirement

For computed requirements purchasers with power sales contracts executed after December 5, 1980, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

- a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers,
- b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers, and
- c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

For computed requirements purchasers with power sales contracts executed prior to December 5, 1980, the purchaser's Computed Average Energy Requirement for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability, as determined pursuant to section IV.B.3 of these General Rate Schedule Provisions.

6. Computed Maximum Requirement

The Computed Maximum Requirement is the larger of the Computed Peak Requirement and the Computed Average Energy Requirement.

7. Operating Demand

The Operating Demand is that demand which is established in accordance with section 5(b) of the purchaser's power sales contract. The Operating Demand shall be contained in the operating agreement and/or the annual operating plan.

8. Curtailed Demand

A Curtailed Demand shall be the number of kilowatts of Industrial Firm Power which results from the purchaser's request for such power in amounts less than the Operating Demand therefor. Each purchaser of Industrial Firm Power may curtail its demand in accordance with the terms of its power sales contract.

9. Restricted Demand

A Restricted Demand shall be the number of kilowatts of Industrial Firm Power which results when BPA has restricted delivery of such power for 1 clock-hour or more. BPA shall make such restrictions in accordance with the terms of the purchaser's power sales contract.

Such Restricted Demand shall be determined by BPA after the purchaser has made its determination whether to accept such restriction or, instead, to curtail its demand for the month.

B. BILLING FACTORS FOR ENERGY

1. Measured Energy

The purchaser's Measured Energy shall be determined in the manner described in this section unless the terms of a power sales contract executed after December 5, 1980, provide otherwise. Measured Energy shall be that portion of the metered and/or scheduled energy which is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy and/or the scheduled energy, as hereinafter defined.

Metered Energy:

The metered energy for a purchaser shall be the number of kilowatthours which are recorded on the kilowatthour meter, adjusted as specified in the power sales contract, and delivered to a purchaser:

- a. at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and
- b. during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.B herein.

Scheduled Energy:

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

- a. for each system for which scheduled energy is the basis for determination of the Measured Energy, and
- b. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

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. 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

The Exchange Adjustment shall be based on the average cost of exchange resources acquired by BPA from:

- a. C. P. National Corporation (CPN)
- b. Idaho Power Company (IPC),
- c. Pacific Power & Light Company (PP&L),
- d. Portland General Electric Company (PGE), and
- e. Utah Power & Light Company (UP&L).

To the extent that the average cost of these exchange resources 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.

There will be an Exchange Adjustment for each of the two rate periods in the rate schedules. Period A begins November 1, 1983, and continues through June 30, 1984. Period B begins July 1, 1984, and continues through June 30, 1985. (Although the rate schedules themselves may stay in effect beyond June 30, 1985, the Exchange Adjustment shall not apply to any sales

made after June 30, 1985.) References for Period B are shown in parentheses immediately following references for Period A.

Purchasers may elect one of the following two Exchange Adjustment options:

Option 1: Monthly adjustments using BPA's estimated billing process. At the end of each rate period, the sum of the monthly adjustments shall be reconciled with a single adjustment for the period using actual bills and costs, or

Option 2: One adjustment for each rate period based on actual bills and costs.

A purchaser which does not provide BPA with a written indication of its choice by December 1, 1983, shall be deemed to have selected the same option as the one applied to its purchases under the 1982 wholesale power rates. If the purchaser selects a different option, BPA shall, if necessary, issue revised power bills to account for the change. The purchaser may not change options while these rate schedules are in effect.

Option 1

For customers electing Option 1, the adjusted monthly bill shall be calculated as follows:

$$AMB = UMB + (EC * .652 * \frac{AMC - 31.1}{31.1} * UMB)$$

(For adjustment in Period B, substitute .632 for .652 and 32.9 for 31.1 in the formula above.)

where:

- AMB = adjusted monthly bill due to BPA;
- UMB = unadjusted monthly bill, which is the total estimated or actual dollar amount due to BPA for service during that month before the Exchange Adjustment is applied;
- EC = the percentage calculated by dividing total exchange costs allocated to the class of service by the total revenue requirement for the class of service; the value for "EC" is provided in the rate schedule for the class of service in question;
- AMC = the average monthly cost (estimated or actual) in mills per kilowatthour (rounded to the nearest tenth of a mill) of all exchange resources acquired from CPN, IPC, PP&L, PGE, and UP&L during that month. Interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase and Sale Agreements) shall not be included in the AMC.

At the end of the rate period either a rebate shall be given or a surcharge assessed to reflect the difference between the effect of a single adjustment for the rate period based on actual exchange costs and loads and the sum of the monthly exchange adjustments based either on actual or estimated costs. First, BPA shall determine the total adjusted bill for Period A (Period B) based on the actual average cost of exchange resources acquired from CPN, IPC, PP&L, PGE, and UP&L during Period A (Period B). The total adjusted bill for Period A (Period B) shall be calculated as follows:

$$TAB = TUB + (EC * .652 * \frac{AAC-31.1}{31.1} * TUB)$$

(For adjustment in Period B, substitute .632 for .652 and 32.9 for 31.1 in the formula above.)

where:

- TAB = total adjusted bill for Period A (Period B);
- TUB = total unadjusted bill which would have been charged to the purchaser for service during Period A (Period B) if no Exchange Adjustment had been applied;
- AAC = actual average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of exchange resources acquired during Period A (Period B) from CPN, IPC, PP&L, PGE, and UP&L. Interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase and Sale Agreements) shall not be included in the AAC.

If $(EC * .652 * \frac{AAC-31.1}{31.1})$ is less than .001, TAB is deemed to equal TUB and no final adjustment shall be made.

(For adjustment in Period B, substitute .632 for .652 and 32.9 for 31.1 in the formula above.)

The sum of the adjusted monthly bills shall then be compared to the total adjusted bill. Either a rebate shall be given or a surcharge assessed to the purchaser to reflect the difference between the two. The rebate or surcharge under Option 1 includes an interest payment and shall be calculated as follows:

$$\text{Rebate (Surcharge)} = (AMB - TAB) * (1 + \frac{INT}{2})$$

where:

- AMB = the sum of the adjusted monthly bills rendered during Period A (Period B); and
- INT = the average short-term interest rate which BPA earns from the U.S. Treasury in Period A (Period B).

Option 2

For customers electing Option 2, the rebate or surcharge for each customer for each period shall be calculated as follows:

$$\text{Rebate (Surcharge)} = EC * .652 * \frac{AAC-31.1}{31.1} * BILL * (1 + \frac{INT}{2})$$

(For adjustment in Period B, substitute .632 for .652 and 32.9 for 31.1 in the formula above.)

where:

- EC = the percentage calculated by dividing exchange costs allocated to the class of service by the total revenue requirement for the class of service; the value for "EC" is provided in the rate schedule for the class of service in question;
- AAC = actual average cost in mills per kilowatthour (rounded to the nearest tenth of a mill) of exchange resources acquired during Period A (Period B) from CPN, IPC, PP&L, PGE, and UP&L. Interest payments made pursuant to Section IV(E) of the Average System Cost Methodology (Exhibit C to the Residential Purchase and Sale Agreements) shall not be included in the AAC;
- BILL = total dollar amount charged the customer for service under this rate schedule;
- INT = the average short-term interest rate which BPA earns from the U.S. Treasury in Period A (Period B).

Provisions for Final Adjustment (Option 1 and Option 2)

The rebate or surcharge based on the actual average exchange costs shall be calculated as soon after July 1, 1984 (July 1, 1985), as possible. Payment of the final adjustment (either the rebate or the surcharge) shall be made within 30 days of the date on the adjustment notice provided to the purchaser.

The final rebate or surcharge shall be subject, with interest, to adjustment upward or downward after July 1, 1985 (July 1, 1986), if the Joint State Board, the Federal Energy Regulatory Commission, a reviewing court, or BPA makes any adjustment prior to July 1, 1985 (July 1, 1986), which changes the actual average cost (AAC, as defined in this section) from the AAC used to calculate the final rebate or surcharge. No adjustment in the rebate or surcharge amount shall be made for any such adjustments made after July 1, 1985 (July 1, 1986).

3. Supply System Adjustment Clause

An adjustment shall be made to the charges for Period B (OY 1985) in those rate schedules which include the Supply System Adjustment. The Supply System Adjustment Clause adjusts for changes in the total cost of Supply System Plants 1, 2, and 3.

The adjustment for each rate schedule shall be calculated as follows:

$$\frac{SS * [((ACT - \$724,300) * .67) + (BUD - \$835,075)]}{BD}$$

where:

- SS = the percentage of total Supply System costs allocated to the class of service in the Cost of Service Analysis for Period B; the value for "SS" is provided in the rate schedule for the class of service in question;
- ACT = the Net Funding Requirements (in thousand of dollars) in the Supply System Annual Budget or amendment thereto for operating year (OY) 1984 as of May 1, 1984;
- BUD = the Net Funding Requirements (in thousand of dollars) in the Supply System Annual Budget for OY 1985, as of June 15, 1984;
- BD = for the Priority Firm Power Rate Schedule, PF-83, the sum of the winter and summer energy billing determinants (in gigawatthours) for the class of service as forecasted in the Wholesale Power Rate Design Study; for the CF-83 Firm Capacity Rate Schedule, the sum of the winter and summer generation capacity billing determinants in megawattmonths; the value for "BD" is provided in the rate schedule for the class of service in question.

This adjustment shall be made if:

$$\frac{[((ACT - \$724,300) * .67) + (BUD - \$835,075)]}{\$1,320,356} \geq .01$$

Prior to July 1, 1984, BPA shall notify the purchaser of:

- a. the differences between the actual OY 1984 Supply System costs and those in the Revenue Requirement Study for OY 1984, and/or
- b. any revisions in the OY 1985 Supply System Annual Budget not reflected in the Revenue Requirement Study for OY 1985.

BPA shall mail affected parties a summary of the changes and a statement of the unit adjustment caused by those changes. In addition, BPA will hold an informational customer meeting to explain the changes.

SECTION IV. OTHER DEFINITIONS:

A. Restriction of Deliveries

Deliveries of capacity and/or energy to any purchaser may be restricted when operation of the facilities used by BPA to service such purchaser is:

1. suspended,
2. interrupted,
3. interfered with,
4. curtailed, or
5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

B. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser will be designated as a computed requirements purchaser if:

- a. it is so designated in its power sales contract executed after December 5, 1980, or
- b. if it has one or more potential abilities as described in paragraphs (1) and (2) below:
 - (1) Such purchaser has generation of its own which can be sold in such a way as to increase BPA's obligation to deliver firm power to that purchaser because of such sale or,
 - (2) such purchaser has the ability to redistribute generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal system.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract for all computed requirements purchasers with power sales contracts executed after December 5, 1980.

For computed requirements purchasers with power sales contracts executed before December 5, 1980, the amount of capacity and energy required for

normal and prudent operations is that which would be sufficient to meet the load and provide adequate reserves through the most critical water or other conditions which might reasonably be expected to occur. Purchase on a computed requirements basis for a purchaser with a power sales contract executed before December 5, 1980, depends on the relationship of the purchaser's resource capability to the purchaser's system requirements. Thus, the billing factors to be applied to such a computed requirements purchaser for any month cannot be determined until after the end of the month. As each such purchaser must estimate its own load and is in the best position to follow that load from day to day, it is the purchaser's responsibility to request scheduling of power from BPA.

3. Definitions and Terms Relating to Computed Requirements Purchasers with Power Sales Contracts Executed Prior to December 5, 1980

Those purchasers whose power sales contracts were executed prior to December 5, 1980, and who are designated as computed requirements purchasers based on the abilities listed in section IV.B.1.b, above, shall be governed by the terms of this subsection.

a. General Principles:

- (1) The assured peaking capability and assured average energy capability of each of the purchaser's systems shall be determined and applied separately.
- (2) As used in this section, "year" or "operating year" shall mean the 12-month period commencing July 1.
- (3) The critical period is that period, described below, during which the purchaser would have the maximum requirement for peaking or energy from BPA. That period would be determined for the purchaser's system under adverse streamflow conditions and adjusted for:
 - (a) current water uses,
 - (b) assured storage operation, and
 - (c) appropriate operating agreements.

In determining the maximum requirement for peaking or energy from BPA, the firm capability of all resources available to the purchaser shall be utilized in such a manner as to place the least requirement on BPA.

- (4) Critical water conditions are those conditions of streamflow in the operating year or years which would result in the minimum capability of the purchaser's firm resources during the critical period. Those conditions of streamflow are based on historical records as adjusted for:
 - (a) current water uses,
 - (b) assured storage operation, and
 - (c) appropriate operating agreements.

- (5) Prior to the beginning of each operating year, the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on BPA. Such assured capability shall be effective after review and approval by BPA.

- (6) The purchaser's assured average energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on BPA within each year of the critical period. The requirement placed on BPA may increase each year, but by no more than the sum of:

- (a) the purchaser's annual load growth, and
- (b) any reductions in assured average energy capability caused by retirement or loss of one of the purchaser's firm resources.

- (7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver to its load on a firm basis. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to BPA. BPA may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if BPA determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

- (8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability

The purchaser's assured peaking and assured energy capabilities shall be the respective sums of:

- (1) the capabilities of its hydroelectric generating plants based on the most critical water conditions experienced to date on the purchaser's system,
- (2) the capabilities of its thermal generating plants based on such adverse fuel or other conditions which might reasonably be expected to occur, and

- (3) the firm capabilities of other resources made available to the purchaser under contracts executed prior to the beginning of the operating year. The firm capabilities of these acquired resources will be based on the capabilities after adjustment for reserves.

Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) Hydroelectric Generating Facilities

The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the conditions necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that, when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy requirement on BPA for a period of 1 month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify BPA in writing of the assured average energy capability to be applied tentatively to the preceding month. Such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured average energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured average energy capability to be applied to the preceding month, provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured average energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by BPA, shall demonstrate by a suitable regulation study based on critical water conditions:

- (a) that such change could actually be accomplished, and
(b) that the remaining balance of its total critical period assured average energy capability could be developed without adversely affecting the firm capability of other purchaser's resources.

The algebraic sum of all such changes in the purchaser's assured average energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation as indicated by revisions in the monthly distribution of critical period energy capability.

(2) Thermal Generating Facilities

The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such peaking and average energy capabilities shall be based on those adverse fuel or other conditions that might reasonably be expected to occur. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time, should any such situation arise.

(3) Other Sources of Power

The peaking and average energy assured capability of other firm resources available under contracts to the purchaser shall be determined prior to each operating year.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES:

A. Temporary Curtailment of Contract Demand

The reduction of charges for power curtailed pursuant to the purchaser's power sales contract and section II.C hereof shall be applied in a uniform manner.

B. Energy Supplied for Emergency Use

A purchaser taking Priority and/or New Resource Firm Power shall pay in accordance with the Nonfirm Energy Rate Schedule, NF-83, and Emergency Capacity Rate Schedule, CE-83, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or
2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefor settled under exchange agreements.

C. Application of Rates During Initial Operation Period

For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

1. direct-service industrial purchasers having new, additional, or reactivated plant facilities, and
2. utility purchasers serving such an industrial purchaser with power purchased from BPA.

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

Any rate schedule provisions regarding Contract Demand, billing demand, and minimum monthly charges which are inconsistent with this section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by BPA, be extended beyond the initial 3-month period for such additional time as is justified by the developmental character of the operations.

D. Construction, Test and Start-up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.
2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.
3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

SECTION VI. BILLING INFORMATION:

A. Billing for Purchasers With More Than One Point of Delivery

Purchasers shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule or schedules unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purposes of these rate schedules and GRSP's, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's noncoincidentally billed points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery.

When the contract provides for billing on a coincidental demand basis, a charge shall be assessed for the diversity among the purchaser's coincidentally billed points of delivery unless BPA elects to waive such charge in whole or in part. The purpose of the diversity charge is to compensate BPA for lost revenue due to coincidentally combining demands from multiple points of delivery. Such a charge shall be applied in a uniform manner among purchasers and shall be specified in the power sales contract.

B. Determination of Estimated Billing Data

If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

C. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

D. Payment of Bills

Bills for power shall be rendered monthly and shall be payable at the Division of Fiscal Accounting and Disbursement located in BPA's Headquarters at 1002 NE Holladay Street, Portland, Oregon. Payments by mail should be sent to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating

any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If BPA is unable to render the purchaser a monthly bill which includes full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same repayment provisions as shall a final bill.

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25 percent) of the unpaid amount or \$50. In addition, a charge of one-twentieth percent (0.05 percent) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest.

