1 of 2

BONNEVILLE POWER ADMINISTRATION
WHOLESALE POWER AND TRANSMISSION RATE
PROJECTIONS
1993-2014

AND

HISTORICAL WHOLESALE POWER RATES
1939-1992

November 1993

MASTER

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COMMONLY USED ACRONYMS

ac	Alternating Current
aMW	Average Megawatt
ASC	Average System Cost
BASC	Bonneville Average System Cost
BGP	Burbank, Glendale, Pasadena (Power Sales Contract)
BPA	Bonneville Power Administration
Btu	British Thermal Units
CBP	Columbia Basin Project
CE	Emergency Capacity (Rate)
COE	United States Army Corps of Engineers
COSA	Cost of Service Analysis
CRC	Critical Rule Curve
CT	Combustion Turbine
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
EA	Environmental Assessment
EIS	Environmental Impact Statement
ET	Energy Transmission (Rate)
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
FPT	Formula Power Transmission (Rate)
FSEA	Federal Secondary Energy Analysis
FY	Fiscal Year (Federal, Oct - Sep)
GPU	Generating Public Utility
GRSPs	General Rate Schedule Provisions
GTRSPs	General Transmission Rate Schedule Provisions
IN	Northern Intertie Transmission (Rate)
IOUs	Investor-Owned Utilities
IR	Integration of Resources (Rate)
IS	Southern Intertie Transmission (Rate)
ISC	Investment Service Coverage
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LTAP	Long-Term Intertie Access Policy
LTTRM	Long-Term Transmission Rates Model (computer model)
mills/kWh	Mills per kilowatthour
Maf	Millions of Acre Feet
MCA	Marginal Cost Analysis

MW	Megawatt (1 million watts)
MWh	Megawatthour
NEPA	National Environmental Policy Act
NF	Nonfirm Energy (Rate)
NFP	NonFederal Participation
NFRAP	Nonfirm Revenue Analysis Program (computer program)
NMFS	National Marine Fisheries Service
NR	New Resource Firm Power (Rate)
NSGPU	Non- and Small Generating Public Utilities
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OY	Operating Year (Federal hydro system, Aug-Jul)
PA	Public Agency
PIP	Programs in Perspective
PF	Priority Firm Power (Rate)
PNCA	Pacific Northwest Coordination Agreement
PNW	Pacific Northwest
PS	Power Shortage (Rate)
PSW	Pacific Southwest
RAM	Rate Analysis Model (computer model)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
SPM	Supply Pricing Model (computer program)
TRDS	Transmission Rate Design Study
USBR	United States Bureau of Reclamation
VI	Variable Industrial Power (Rate)
VOR	Value of Reserves
WNP	Washington Nuclear Project
WPPSS	Washington Public Power Supply System
WPRDS	Wholesale Power Rate Development Study

SPECIFIC TERMS AND DEFINITIONS

Eastern Intertie (IE)	Nonfirm, energy only
Energy Transmission (ET)	Nonfirm Network, energy rate
Formula Power Transmission (FPT)	Firm Network, mileage-based demand charges
Integration of Resources (IR)	Firm Network, demand and energy
Iowa Curves	Percentage retirements for types of industrial equipment illustrating unique retirement patterns. Twenty-two (22) types have been identified of which BPA uses six (6). Curves, denominated in percent per 10th of lifetime, run from 0 to 1200%.
Main Grid	Includes the Network plus Other Primary
Near-Term	Years from 1993-2002: portion of forecast period covered by BPA 10-year programs
Northern Intertie (IN)	Nonfirm Intertie North, energy only
Other	Segments of the Federal Columbia River Transmission System (FCRTS) not involving general wheeling rates, namely Generation-Integration, Fringe, Public Agency, DSI and IOU delivery segments
Out-Years	Years from 2003-2015: portion of forecast period beyond BPA programs for which investments must be modeled
Plant Placements	Sum of plant replacements and plant additions: total plant increment
Primary	Plant amounts of the FCRTS other than General Plant
Renewal Rates	Units of the Iowa-type curves

Repayment	BPA's method for computing plant carrying costs which minimizes interest costs while considering financing replacements associated with a test period rate-base for 50 years
Required Net Revenues	In this study, subsumes planned amounts: represented by acronym - RNR
Revenue Requirements	In this study represented by acronym - RRQ
Segments	Nine (9) commercial categories of the FCRTS including Network, PSW, Northern, and Eastern Interties, and those mentioned under Other above.
Southern Intertie (ISA) (IBS)	Nonfirm Intertie South, energy only Firm Intertie South, demand and energy
System Replacements Program	BPA's 10-year transmission system replacements program: represented by acronym - SRP
Townsend Garrison Transmission (TGT)	BPA's portion of the Montana Intertie running from Townsend to Garrison, Montana. TGT is a firm rate developed in the contracts with the owners of Colstrip generation paying for BPA's transmission facilities east of Garrison
Transmission System Development Program	BPA's 10-year transmission development program: represented by acronym - TSDP

I. INTRODUCTION AND SUMMARY OF RESULTS

A. Introduction

This document provides a range of high, medium, and low case long-term projections of Bonneville Power Administration's (BPA) wholesale power rates and a medium case long-term projection of BPA's wheeling rates. These projections are produced annually by BPA. BPA uses these projections in long-term marketing, resource, transmission, and financial planning assessments. BPA's projections also are used by public utility commissions, utilities, and others for a variety of planning purposes.

The analysis used for these rate projections assumes that current rate making methodologies continue into the future and are further based on certain assumptions about regional loads, extra-regional markets, the costs of resources, BPA's financial requirements, and the capability of the region's power plants. While these projections are intended to address the overall uncertainty in rate levels, BPA realizes that the future will not reflect any specific set of assumptions.

The rate projections in this document have been prepared prior to the Draft 1993 BPA Marketing Plan, the implementation of which is almost certain to push BPA away from any set of assumptions in this document. Therefore, this document can be thought of as representing the "old" BPA with its products and policies. It can be viewed as a starting point or reference point to measure the impact of the "new" BPA with its Marketing Plan, and the broader undertaking referred to as the Competitiveness Project. Two possible results of these major efforts are tiered rates and the unbundling of power products and services. If

adopted, these changes in BPA products and policies would be reflected in BPA's forecasted rates, and hence a new set of projections would be produced and made available to BPA's customers.

A Marketing Plan scenario has been added to the PF power rate forecast in this document. This scenario shows the direction of movement in PF rates due to the Marketing Plan, but the use of a range portrayal cautions that exact details of the final comprehensive Marketing Plan are unknown at this time. One of BPA's goals for the Marketing Plan is that it results in a more competitive BPA and lower rates for the general requirements of BPA's customers than would otherwise be the case.

The current set of projections are intended for long-term analysis only and do not imply any final determinations by the Administrator regarding issues that may be the subject of future BPA rate proceedings.

In addition, because these projections are average rates, they may not be applicable to particular individual utilities because of differences in load factor. However, for some rates, a table has been included which separates the average rate into demand and energy charges based on BPA's current rate design.

BPA develops wholesale rate projections under three scenarios (high, medium, and low) through Fiscal Year (FY) 2014 using the Supply Pricing Model (SPM). BPA's fiscal year begins October 1 and ends September 30. The SPM uses detailed data on resource output and cost, transmission, distribution, conservation, and overhead costs to estimate

average rates given a set of electricity loads. The SPM projects annual average electricity rates for BPA's wholesale power customers following the rate directives contained in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and methodologies established in previous BPA rate proceedings.

Since BPA's last rate projection document, published in November 1992 (BPA: Wholesale Power and Transmission Rate Projections for 1992-2013, November 1992), several factors affecting projection of rate levels have changed. The load forecast used in the SPM has been updated to the forecast that will be in BPA's 1993 White Book. In addition, the SPM has been updated to use 1993 Final Proposal rate case budget and revenue requirement data. The existing system resource operation is consistent with the 1992 White Book. The acquisition of new resources and conservation costs are consistent with BPA's 1992 Resource Program. Snake and Columbia River flows are consistent with the Northwest Planning Power Council (Council) Phase II Fish and Wildlife Amendments.

BPA developed the long-term Transmission Rates Model (LTTRM) to prepare the medium case long-term projections of BPA's network and Intertie wheeling rates. The LTTRM uses detailed data regarding transmission plant, operating and maintenance costs, and firm and non-firm wheeling loads to estimate long-term wheeling rates. The model is consistent with the Transmission Rate Design Study (TRDS) methodologies established in previous BPA rate proceedings.

BPA's general wheeling rates, other than FPT, have been forecast through 2015 using published and model derived data. Rate methods of the 1993 rate case are used including recent refinements to revenue requirements for non-Federal participation (NFP) in BPA's PSW AC Intertie, and changes to the PSW Intertie cost-of-service. Transmission interest and PSW Intertie depreciation are reduced for anticipated upfront payments for NFP; allocable PSW Intertie costs are assigned on the basis of total usage rather than BPA's standard contribution to peak method.

Additionally, the PSW Intertie firm rate (ISB) demand charge is calculated on usage rather than Intertie capacity as was the method from 1985 through 1991. Only a median or base-case forecast is presented.

Factors affecting high and low wheeling rates across different transmission segments are not modeled at this time. Pertinent theory and information are utilized to minimize but not eliminate the role of assumptions. Data and assumptions are listed below in Section V.

Rates projected include firm and nonfirm Network under IR and ET, firm and nonfirm Intertie South from ISB and ISA, and the nonfirm Intertie North (IN) rate. Intertie East costs, revenues from TGT, and PSW Intertie AC annual cost payments for NFP are estimated from methods employed in the 1993 rate case. Eastern Intertie services credit the entire FCRTS; revenues from NFP benefit the PSW Intertie. FPT, although not forecast per se, should track the IR demand charge.

The analysis used for these rate projections assumes that current rate making methodologies continue into the future and are further based on

certain assumptions about regional loads, extra-regional markets, transmission system costs and segmentation, BPA's financial requirements, and the capability of the region's power plants. While these projections are based on reasonable assumptions, BPA realizes that the future will not reflect any specific set of assumptions. These projections are intended for long-term analysis only and do not imply any final determinations by the Administrator regarding issues that may be the subject of future BPA rate proceedings.

B. Summary

Under the assumptions used in the Medium Case forecast in this document, BPA's wholesale power rates would increase about 9 percent in the FY 1996/1997 period from current FY 1994/1995 levels. Thereafter, the rate of growth would be more modest .

BPA's priority firm (PF) rate would increase in real (1993\$) terms from 26.5 mills/kWh in FY 1994 to 28.2 mills/kWh in FY 2014, an average annual increase of about one third of 1 percent (0.33 percent) per year. In nominal terms, the PF rate would grow at an average annual rate of 3.52 percent in that time period. In real 1993 dollars, the PF rate increases through FY 2003, reaching 28.9 mills/kWh in that year. After FY 2003, the real PF rate is projected to decrease through FY 2009, increase to 28.9 mills/kWh in FY 2011, and then decrease to 28.2 mills/kWh by FY 2014.

The pattern of growth in the real 1993 dollar PF rate is closely correlated with BPA's plan for aggressive acquisition of conservation through FY 2003 and the Supply Pricing Model's forecasted need for new resources in FY 2010-11.

Through the Marketing Plan, BPA is planning to take actions that will reduce or avoid these rate increases. None the less, BPA is publishing these projections as a continuation of a service we have provided to our customers on a consistent basis since 1988. We encourage our customers to use these rate projections as updates of last years projections, not as the BPA forecast of what our future rates will actually be under the new BPA Marketing Plan and Competitiveness Project regime.

Wheeling rate projections are shown in Tables 16 and 17. Table 16 is in nominal dollars; the rates in 1995 are the current BPA wheeling rates. Table 17 expresses the rate levels in late-1993 dollars. Positive average annual growth rates at the bottom of this table indicate rate increases greater than anticipated inflation; conversely for negative overall real growth rates. The Intertie South ISA rate shows a tendency to stay flat or even fall in *nominal* terms in the near term. At no point even in the long term does ISA outstrip inflation. The Network rates, however, show a tendency to increase faster than inflation in the long term. ET surpasses ISA in 2014.

As Charts 8 and 9 show, nominal forecasts are generally lower than last December's projections. Nonetheless, Network rates are forecast to

exceed inflation, particularly in the long term under base-case assumptions. Network load increases and offsets from BPA Nonfirm are forecast to be overtaken by Network cost increases and share increases to wheeling. Long-term pressures on the Network rates are still, as last time, owing to the assumptions of Network plant growth continuing at its current (near term) levels and the assumption that general plant continues to escalate faster than producers' prices. The immediate increase in the PSW rates are due to a trough in the spot market forecasts coinciding with the strength of the California economy. Northern Intertie costs increase as projects are completed--first, Bellingham area reinforcement followed by construction to Oliver in 2000. Costs level out and decline as interest costs are segmented to the main grid growth areas after 2002.

II. POWER RATES FORECAST

A. Supply Pricing Model

The Supply Pricing Model (SPM) is a computer model that simulates BPA's rate setting process. BPA developed the model to analyze the probable rate impacts of alternative BPA policies and actions. The SPM can produce long-term projections of annual average BPA wholesale rates and annual average regional retail rates or mid-term projections of monthly average retail rates for public utilities. The SPM projects the Priority Firm Power (PF) rate, Industrial Firm Power (IP) rate, New Resource Firm Power (NR) rate, Surplus Firm Power (SP) rate, the average cost of nonfirm energy, and BPA's average system cost. The model also projects retail rates for the residential, commercial, irrigation, and industrial sectors of both private and public utilities for use in load forecasting.

The SPM contains capacity and cost information on both generating and conservation resources. The cost and capacity of pre-1985 Federal base system hydroelectric resources are included as totals; however, most other resources are treated individually. Capital and operating costs are specified for each generating resource. For conservation resources, only those costs that are to be paid through electricity rates are included.

The costs of generation and conservation are summed for the various owners (BPA, investor-owned utilities (IOU), and public utilities). The costs of resources used to provide power to customers of BPA, public utilities, and IOUs are combined to reflect contractual agreements among utilities and provisions of the Northwest Power Act such as the

residential exchange. The SPM develops forecasts of BPA's costs and allocates them to rate pools (priority firm, direct service industries (DSIs), new resources, and surplus power). Similarly, costs are developed for investor-owned and public utilities. Retail markups are added to these costs to obtain estimates of retail rates for each consuming sector by utility type.

As electricity use grows, resources are added, and the new resource costs are melded with existing resource costs. The SPM balances resource supply and demand based on the critical water capacity of the hydro system. Water conditions over 50 historical years are used to determine nonfirm energy availability on average. This nonfirm energy is allocated to various uses according to a set of priorities specified in the model: (1) service to the first quartile of the DSI load; (2) displacement of combustion turbines related to the WNP-3 Settlement; (3) displacement of firm purchases; (4) displacement of regional high-cost thermal generation; (5) export to the Southwest; and (6) displacement of regional low-cost thermal generation. Firm energy surpluses remaining after contractual obligations have been met are allocated using the same priorities.

1. History

The current version of the SPM evolved from BPA's original energy model, the Integrated Supply/Demand Model (ISDM). The ISDM combined the relationship between the demand and supply of electricity, linked by the price of electricity, into a single model.

The demand portion of that model was based on a methodology prepared by National Economic Research Associates, Inc., for the Pacific Northwest Utilities Conference Committee. The supply and pricing portions of the ISDM were developed by BPA in 1976. The ISDM forecasted both loads and rates and was used to analyze policy alternatives for BPA's **Final Environmental Impact Statement: Wholesale Rate Increase (1979)**. The supply and pricing portions were subsequently removed from the ISDM and incorporated into the SPM.

BPA continues to revise the SPM as needed to reflect the changing economic conditions and policies in the region. A major modification was the incorporation of the load, resource, and rate provisions of the Northwest Power Act. The SPM also underwent extensive modification as a result of its use in implementing the Northwest Power Act section 7(b)(2) rate test methodology. The SPM received close examination from interested parties outside BPA. Many of their suggested changes were incorporated during the formal proceedings held to develop the section 7(b)(2) methodology and during the methodology's initial implementation in the 1985 rate filing.

2. Uses

In conjunction with demand and resource planning models, the SPM is used to produce retail rate inputs to long-term load forecasts. The SPM has been used to analyze rate impacts for

environmental analyses and a wide variety of BPA policy decisions. For example, the SPM was used in analysis which supported BPA's successful efforts to refinance high interest Washington Public Power Supply System bonds. The SPM also projects monthly mid-term rates for non-generating and generating public utilities; these rates are used as inputs to forecast the mid-term loads of these utilities for BPA rate filings, and for developing BPA's portion of the Pacific Northwest Coordination Agreement forecast.

As mentioned above, the SPM also is used to conduct the rate test provided for in section 7(b)(2) of the Northwest Power Act.

Section 7(b)(2) requires that the BPA rates to be charged to public utility and Federal agency customers for a specified 6-year period be no greater than the rates that would have been charged had a set of specific assumptions been made. These assumptions regarding loads, resources, and costs are outlined in section 7(b)(2) and have been incorporated into the SPM.

B. Methodology

The following sections describe how the SPM develops rate projections by simulating BPA's wholesale power rate setting process.

1. Inputs

Various categories of data are used in the SPM to project rates. BPA budget data include BPA's administrative and general costs, operation and maintenance costs, borrowing from the Federal

Treasury, and other sources. Another data category consists of transmission and distribution costs. Individual hydro and thermal plant resource costs and capabilities are input, as are the costs and capabilities of new, unnamed, generic resources required to meet loads over the study period. The mix of new resources is developed using the BPA/Council's ISAAC model. The various contractual and treaty agreements that BPA has with regional utilities and Canada constitute another category of data. The SPM updates resource cost projections using deflator/escalator projections developed by DRI/McGraw-Hill. These cost projections include: utility construction costs, operation and maintenance, inflation and interest rates, and fuel costs. The SPM's fuel price forecast uses a forecast of Pacific Southwest (PSW) natural gas prices to determine revenue from sales of economy energy on the open market. The PSW natural gas price forecast is based on BPA's forecast of natural gas prices at the wellhead. The wellhead price is marked up for transportation costs and tariffs to derive a generating electric utility burner tip price. The last category of data input to the SPM are long-term load forecasts for public and private utilities by consuming sector (residential, commercial, irrigation, and industrial).

2. Load/Resource Balance

The demands for electricity by public and investor-owned utilities in the region by consuming sector, by BPA's direct-service industrial (DSI) and Federal agency customers, and other

contractual requirements are entered into the SPM. Where appropriate, these loads are reduced by the amount of conservation being acquired as a resource in BPA's 1992 Resource Program. Federal System hydro losses resulting from the Snake River flow augmentation provisions of the Council's Phase II Fish and Wildlife Amendment are reflected as firm losses and reflected in firm hydro output. The Columbia River Flow Augmentation to store an additional 3 MAF is accomplished operationally through changes in secondary energy and short-term power purchases.

Contractual obligations and generation from existing resources are consistent with BPA's 1992 White Book. New generating resource acquisitions are consistent with BPA's 1992 Resource Program. The capability of on-line hydro facilities under critical water (based on stream flows in the Columbia River during the four worst consecutive years in the historical record) and available energy from on-line thermal resources are compared with loads for the public, IOU, and Federal systems to determine a load/resource balance for each system.

The loads of all public utilities that cannot be served by their own existing resources and for which no additional resources are brought on-line are assumed to be served by the Federal system. If the on-line resources in a given year are not capable of meeting the public or Federal system load, the SPM adds generic new resources identified by the ISAAC model. Similarly, investor-owned utilities

are assumed to build or acquire resources identified in the ISAAC model to meet their own load growth.

If resources exceed firm loads in any year, the surplus firm power is first used to serve firm contracts, and any remaining power is then sold in the nonfirm energy market. Any public or IOU surplus is assumed to be sold at each utility group's aggregate average system cost.

The SPM places all BPA resources into three resource pools: (1) Federal Base System (FBS); (2) exchange; and (3) new resources. Resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves PF loads (contract, Federal agency, public utility, and exchange loads) until FBS resources are exhausted. The exchange resource then is used to serve any remaining PF load. Remaining FBS, exchange, and new resources are used to serve the remaining DSI, New Resource, and surplus firm power loads.

3. Revenue Requirement

The SPM calculates BPA's revenue requirement for each year of the projection period by estimating individual resource cost components and other BPA costs. Interest and amortization on Federal resources are determined by means of separate repayment study simulations for transmission and generation investments. These annual payments are combined with the annual costs of fuel

and operation and maintenance (O&M), which are escalated over time, to project Federal generation costs. Payments on the debt for the net-billed portions of the Supply System nuclear plants are entered into the SPM directly. The cost of exchange resources is determined on an annual basis from the average system cost of all participating private and public utilities. Finally, the budgeted annual expenditures for transmission, conservation, administrative and general, and fish and wildlife costs are included with planned net revenues to determine the total revenue requirement in each year.

4. Cost of Service

The cost of service step of the SPM assumes resource operation under critical water conditions; that is, nonfirm energy is not available. Allocation of projected costs to customer classes is performed on an energy (as opposed to capacity or demand) basis. Generation costs are allocated according to the results of the load/resource balance based on critical water generation. Conservation costs, BPA administrative and general expenses, Supply System Nuclear Project No. 3 (WNP-3) Settlement Agreement costs, and capacity surplus sales are allocated across all BPA firm loads. Federal transmission costs are allocated to customers served with Federal resources. Transmission costs related to exchange resources are allocated together with exchange generation costs. In general, the cost allocation procedures are the same as those in BPA's 1993 final rate proposal.

5. Revenue Adjustments

The SPM makes several adjustments to the allocated costs of service to calculate the final BPA rates. These adjustments include the excess revenue credit; the WNP-3 credit; the surplus firm power revenue deficiency; the WNP-1 credit; the section 7(c)(2) margin and delta, incorporating the IP-PF rate link and Variable Industrial Power (VI) rate determination; the DSI floor rate adjustment; and the exchange cost adjustment.

Excess revenues are earned from the sale of nonfirm energy that is available by assuming better than critical water. The SPM calculates the expected service to specified nonfirm energy markets described in Section 2 above. The SPM calculates an annual average nonfirm energy rate, which is a function of forecasted PSW natural gas prices capped by the average cost of nonfirm energy. This rate is applied to the calculated amount of nonfirm energy sales that serve the regional high-cost thermal displacement, purchase displacement, and PSW markets. Low-cost thermal displacement sales are assumed to be made at a lower rate. The revenues from these sales are credited to loads served by FBS and new resources.

The WNP-3 credit accounts for the revenues BPA expects to receive from the IOUs in fulfilling the WNP-3 Settlement Exchange Agreement. The revenues that result from applying the forecasted rates to the load are allocated to all firm loads.

DSI first quartile loads are not allocated costs, since resources are neither planned nor acquired to serve this load. Instead, service to the first quartile uses a combination of nonfirm energy, surplus firm energy, and provisional drafts. The opportunity costs, or revenues, which BPA would have received for this power in other markets are charged to the DSIs, thereby increasing their allocated costs. The opportunity cost assigned to the first quartile is included in the excess revenue adjustment and thus credited to loads served by FBS and new resources.

The surplus firm power revenue deficiency results when less than all of the available surplus firm power is assumed to be sold at its fully allocated cost. A portion of the unsold surplus firm power serves the DSI first quartile, and the remaining power is sold at market-based rates. The opportunity cost for serving the first quartile and the rates for the remaining sales are a function of forecasted natural gas prices capped by the fully allocated cost of surplus firm power. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that surplus, equals the surplus firm power revenue deficiency. The deficiency is allocated to all firm loads, including sales of surplus firm power at fully allocated cost.

The WNP-1 exchange revenue surplus is allocated after the surplus revenue deficiency. Beginning July 1991 and ending June 1996, the IOUs purchase WNP-1 exchange power at a negotiated rate

that is higher than the PF rate. These "surplus" revenues are allocated to loads served by the FBS, excluding the WNP-1 exchange load.

The 7(c)(2) adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. It incorporates any revenue variance due to the forecasted effective VI rate being higher or lower than the plateau rate. The IP-PF link is used in determining the applicable DSI rate through the forecast period. The link subsumes the value of reserves adjustment and the 7(c)(2) margin adjustment. The applicable link is .38 mills/kWh in 1987 dollars. The VI rate is determined by establishing a plateau rate for a range of aluminum prices. If the price of aluminum is either lower or higher than this range, the VI rate is adjusted either downward or upward from the plateau rate. Any deficiency or surplus due to aluminum prices outside the range for the plateau rate becomes part of the 7(c)(2) adjustment and is allocated to all firm loads. The floor rate test ensures that the DSI rate will not be lower than the Industrial Firm Power rate in effect for Operating Year 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the DSI rate is below that floor rate, the DSI rate is raised to the floor rate, and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

The exchange cost adjustment alters BPA's revenue requirement, because changes in the PF rate result in changes in the cost of the

residential exchange. The SPM repeats the exchange cost calculation several times to reflect changes in the PF rate due to subsequent cost allocations and revenue adjustments.

6. Retail Rates

The SPM calculates retail rates for public and private utilities for each consuming sector. To develop rates for private utilities, the SPM calculates an average system cost using the utilities' own generation costs, transmission costs, costs of power purchases from BPA, and other appropriate costs. The private utilities' commercial and industrial rates are based on the utilities' average system cost. However, the private residential rate reflects benefits of the residential and small farm power exchange. Public utility retail rates are based on the melded cost of their BPA purchase power and their own generation and transmission costs. For both private and public utilities, distribution costs associated with each customer group are added to derive the final retail rates.

C. Data And Assumptions: Power Rates Forecast

The high, medium, and low rate projections in this document attempt to reflect the uncertainty involved in projecting future rates. The scenarios are intended to capture the range of quantitative outcomes of the probable events or series of events that could occur.

The medium case rate projection is developed first. The assumptions made for the medium case then are modified to develop the high and low rate projections. The major assumptions used in the medium, high, and low rate projections are discussed below and are summarized in Figure 1.

Figure 1
Assumptions For Low, Medium and High Rate Projections

	<i>Low Case High</i>	<i>Medium Case Medium</i>	<i>High Case Low</i>
1. Fuel Price Forecast (June 1992)			
2. Surplus Firm Sales	<i>All contracts in Power Sales mode</i>	<i>All contracts in Power Sales mode for all years except for one PSW contract in 1995 only.</i>	<i>PSW contracts converted to capacity/energy exchange for all years.</i>
3. Revenue Requirement ^{1/}	<i>-\$200 million</i>	<i>---</i>	<i>+\$200 million</i>
4. Federal Hydro Derate	<i>None</i>	<i>None</i>	<i>250aMW critical, 20aMW nonfirm</i>
5. Resource Cost ^{2/}			
Thermal	<i>-10%</i>	<i>---</i>	<i>+10%</i>
Hydro	<i>-20%</i>	<i>---</i>	<i>+20%</i>
Renewable	<i>-20%</i>	<i>---</i>	<i>+20%</i>
Conservation	<i>-10%</i>	<i>---</i>	<i>+10%</i>
6. Load Forecast ^{3/}			
Utility	<i>Medium/Low</i>	<i>Medium</i>	<i>Medium/High</i>
DSI	<i>Medium/Low</i>	<i>Medium</i>	<i>Medium/High</i>

^{1/} Allocated to all firm load.

^{2/} Capital, O&M, and fuel costs are adjusted for resources that are available to be added to avoid energy deficits.

^{3/} Utility loads: 1991 Joint for low and high cases (reduced for 1992 Resource Program conservation).
Medium case is the 1993 White Book load forecast (reduced for 1992 Resource Program conservation).

1. Medium Rate Projections

- New IOU resources available include combustion turbine, cogeneration, small hydro, efficiency improvements, wind, and geothermal.
- Annual conservation savings are treated as load reductions. It is assumed that the cost of cost-effective conservation programs to meet IOU needs would be borne by the IOUs. Conservation costs for those IOUs are allocated to IOU rates. Public utilities are assumed to have signed BPA conservation contracts, and the costs of these programs are allocated to BPA rates.
- Surplus energy is calculated annually within the model, and contracts are served up to that amount. Any remaining surplus firm power in any year of the projection is sold at nonfirm energy rates depending on market prices based on fossil fuel prices. Surplus firm power sales are assumed to reduce the size of the PSW nonfirm energy market by the amount of the firm sales. When surplus firm power is sold as nonfirm energy, the difference between the fully allocated cost and revenues from sales at the nonfirm energy rate is allocated to all firm loads. For the surplus power contracts, if the contract rate is higher than the full cost rate, then a credit is allocated to all firm loads; if the contract rate is lower than the full cost rate, then the deficiency is allocated to all firm loads as in the case of surplus firm being sold as nonfirm.
- Federal firm purchase power of 405 aMW in 1994, 342 aMW in 1995, and 86 aMW in 1996 are assumed. Thereafter sufficient new resources are acquired to meet Federal load.
- All private utilities are assumed to exchange their eligible residential and small farm loads with BPA as provided for in the Northwest Power Act. The level of public utility participation is projected outside the SPM.
- All public and private utilities, with the exception of Utah Power and Light, are assumed to have signed net requirements contracts with BPA. These contracts obligate BPA to meet any loads that a signing utility cannot meet with its own resources. No new large single loads on public

agencies are assumed. The private utilities are assumed to build or acquire resources to meet all future load growth.

- The third alternating current (AC) Intertie (without participation) assumptions are an additional 800 MW in service in FY 1993 and another 800 MW in service in FY 1994.
- Inflation and asset-specific escalation projections obtained from Data Resources, Inc., in August of 1993, are used for projecting various costs over the forecast period.
- No replacement of terminated or retired FBS resources is assumed.
- The current DSI contracts are assumed to be renewed in their existing form upon their expiration date.
- The DSI Variable rate is assumed to be in place through FY 1996. In addition, the IP-PF link is assumed to be in place over the term of the forecast.

2. High Rate Projections

- New resources, including those for the IOUs, are assumed to cost 10 percent more for thermal resources and 20 percent more for hydro and other renewable resources than in the medium case. These costs include capital, fuel, and operating costs.
- Conservation costs are higher than the medium case and further increased by 10 percent. Conservation costs and savings are higher compared to the medium case due to the higher load assumption.
- All Pacific Northwest signed contracts for surplus firm power are assumed to be served in the power sale mode in the high case. All Pacific Southwest contracts are assumed to be converted to capacity for energy exchanges throughout the projection period, coinciding with the need to acquire new resources.
- A low fuel price forecast developed by BPA is used, which reduces revenues from nonfirm energy and spot market sales of surplus firm power.

- The medium/high case final 1991 Joint Bonneville/Northwest Power Planning Council Long-Term Load Forecast is used for all loads. Conservation reductions are the same as those in the medium case through 2003. A medium/high case from ISAAC is used to estimate reductions for the remaining years.
- In order to capture the uncertainty associated with unforeseen changes in BPA's revenue requirement, an additional \$200 million in nominal dollars is allocated over all firm power loads in each year.
- The Federal hydro system is derated by a selected option in the System Operation Review Study. Critical hydro is reduced by 250 aMW and nonfirm generation is reduced by 20 aMW.

3. Low Rate Projections

- New resources, including those for the IOUs, are assumed to cost 10 percent less for thermal resources and 20 percent less for hydro and other renewable resources than the medium case.
- Conservation costs are lower than the medium case and further decreased by 10 percent. Conservation costs and savings are lower compared to the medium case due to the lower load assumption.
- All surplus firm power contracts are assumed to be served in the power sale mode in the low case.
- A high fuel price forecast developed by BPA is used, which increases revenues from nonfirm energy and spot market sales of surplus firm power.
- The medium/low final 1991 Joint Bonneville/Northwest Power Planning Council Long-Term Load Forecast is used for all loads. Conservation reductions are the same as those used in the medium case through 2003. A medium/low case from ISAAC is used to estimate reductions for the remaining years.
- The revenue requirement in each year is reduced by \$200 million in nominal dollars, and the credit is allocated over all firm power loads

D. Results

The detailed results for the medium, high, and low rate projections are presented on Tables 1 through 5. The tables provide the projections for each of the four wholesale power rates, BPA's average cost of nonfirm energy, and BPA's average system cost. The results are expressed in real (inflation-adjusted) 1993 mills per kilowatt-hour and in nominal mills per kilowatt-hour.

The 1994 and 1995 rates in these tables are from the "1993 Final Rate Proposal - Documentation for the Revenue Forecast Study", WP-93-FS-BPA-04A, page 370. For remaining years (1996 through 2014), rates are projected using the SPM. The following is a brief discussion of BPA's wholesale rate projections by rate, BPA's average cost of nonfirm energy, and BPA's average system cost.

1. Priority Firm Power Rate

The PF customer class consists of BPA's public agency, cooperative, Federal agency customers, and participants in the residential exchange. Under provisions of the Northwest Power Act, these customers are served first with FBS resources. If the FBS is not large enough to serve their entire load, they are served with exchange resources and then new resources.

The uncertainty that exists about the level of future PF rates is largely a function of the uncertainty associated with the level of

loads placed on BPA; that is, the overall level of regional load growth. Other factors that will affect future PF rate levels, and all other BPA rates, include changes in BPA's revenue requirement, BPA's ability to market surplus firm power at fully allocated cost, and the level of revenues from nonfirm energy sales.

Chart 1 and Table 1 shows the PF rate projections in real (inflation-adjusted) mills per kilowatt-hour for the high, medium, and low cases. The 1994 and 1995 rates, as stated earlier, are based on the average annual rate estimates used in developing the 1993 rate filing. In real 1993 dollars, the PF rate increases through FY 2003, reaching 28.9 mills/kWh in that year. After FY 2003, the real PF rate is projected to decrease through FY 2009, increase to 28.9 mills/kWh in FY 2011, and then decrease to 28.2 mills/kWh by FY 2014.

This pattern of PF growth is driven by an aggressive conservation acquisition build-up through FY 2003, followed by several years of surplus, then a renewed build-up of conservation acquisitions and an addition of new resources starting in FY 2010-11.

The high case real PF rate increases at an average annual rate of growth of 1.6 percent over the forecast period. The higher load forecast assumption means that new resources must be added by both BPA and the IOUs. This results in higher exchange costs and higher and more new resource costs than in the medium case. The hydro derate increases the unit cost of power from the FBS

resource pool in addition to making less FBS power available to serve PF load. Other factors that increase the PF rate are reduced nonfirm revenues due to a low fuel price forecast, the assumption of no surplus firm power sales at fully allocated cost, and the higher BPA revenue requirement. Conservation savings maintain a stable pattern throughout the forecast horizon.

The low case real PF rate decreases at an average annual rate of growth of .3 percent over the forecast period. Conservation savings have a pattern over the forecast similar to the medium case, and therefore similar swings in rates. Given the lower load forecast used, few new BPA or IOU resources are needed. The low load growth of the IOUs and the decreased cost of resources slow the growth in the cost of exchange resources. The assumptions of a high fuel price forecast (which results in larger nonfirm revenues) and the decreased revenue requirement also reduce the PF rate.

2. Industrial Firm Power Rate

All DSIs were served at the IP rate until BPA developed the Variable Industrial Power rate for aluminum smelter loads in 1986.

Currently, all aluminum smelter loads are served at the VI rate, and the remaining non-aluminum DSIs are served at the IP rate. The rate that VI purchasers actually pay is tied to the price of aluminum. The VI rate is assumed to be effective through June 30, 1996. Chart 2 and Table 2 shows the IP (and VI plateau) rates from the high, medium, and low rate projections. The IP rate

tracks the PF rate closely (Chart 1), since the calculation of the IP rate is linked to the PF rate level; the uncertainty associated with the IP rate is the same as that associated with the PF rate.

3. New Resource/Surplus Firm Power Rates

The NR rate is applied to IOU net requirements loads and any new large single loads of public utilities. The SP rate is applied to sales of surplus firm power to customers within and outside the region. In the SPM, the NR and SP rates are based on the same resource costs and are allocated costs in the same manner. The result is identical rates on an annual average energy basis. The actual rates may vary slightly due to different expected load factors for the two customer classes and different rate schedule provisions. For this study, however, they are considered to be equal.

The NR/SP rate is based on the average cost of all resources remaining after serving the PF load. Exchange cost is currently the primary determinant of the NR/SP rate. Over time, the costs of new resources may have a larger influence on the level of this rate. In all three cases, the NR/SP rate is driven by the Average System Cost of the utilities participating in the residential power exchange and the cost of BPA's new resources.

Chart 3 and Table 3 show the results for the NR/SP rate from the high, medium, and low rate projections. The major sources of uncertainty for this rate are the level of expected IOU load growth,

which affects the average cost of exchange resources, and the amount and cost of BPA's new resources needed to serve load growth placed on BPA. In the medium and high cases, the NR/SP rate rises as the IOUs add increasing amounts of new generation to meet higher load growth. Additionally, the NR/SP rate increases markedly from FY 1995 to FY 1996 due to an increase in BPA's new resources in FY 1996. In the low case, lower loads, and therefore fewer and lower cost resource additions, keep the rate at relatively low levels.

4. Average Cost of Nonfirm Energy

The average cost of nonfirm energy is calculated to be consistent with decisions made in the 1993 rate case which in turn relies heavily on the 1987 rate case. It is based on BPA's average system cost excluding exchange cost and load. Chart 4 and Table 4 show the results for the NF rate from the high, medium, and low rate projections. The real 1993 rate in all three cases is influenced by the conservation expenditure pattern explained earlier. The major areas of uncertainty are similar to those for other rates. They include future cost levels for both FBS and new resources and future load growth. The average cost of nonfirm rate projections must be distinguished from market determined prices that BPA receives for nonfirm energy. As stated earlier in the document, the nonfirm market rate is a function of forecasted PSW natural gas prices capped by the average cost of nonfirm.

5. BPA's Average System Cost

BPA's average system cost (BASC) is determined by dividing BPA's forecasted revenue requirement by BPA's expected total system sales for a given period. The revenue requirement includes total transmission costs, FBS costs, new resource costs, exchange resource costs, and other program generation costs which include WNP-3 settlement costs and conservation costs. BPA's total system sales include: (a) all PF, both general requirements and residential exchange, sales; (b) NR sales; (c) all DSI, including first quartile, sales; (d) all surplus firm power sales; and (e) total nonfirm energy sales. Chart 5 and Table 5 shows the results for BASC from the high, medium, and low rate projections. BPA's average system cost tracks the PF rate projections for all three cases.

6. Market Plan Scenario

A market-plan PF rate scenario was produced using the medium case rate projection as a base. Simplified assumptions about the proposed draft BPA Marketing Plan and Competitiveness Project were used to produce a broad band of possible PF rates. These assumptions include savings from productivity gains and program reductions as well as increased revenues from new products and services. This scenario is meant to show the direction of movement in PF rates due to BPA's Marketing Plan and Competitiveness Project, but the use of a range portrayal cautions that exact details

are unknown at this time. Chart 6 shows the market-plan PF range in nominal terms as well as the nominal PF rates from the medium, high, and low cases. A goal of BPA's Marketing Plan and Competitiveness Project is that they will result in lower power rates to requirement service customers than would otherwise be the case.

III. TRANSMISSION RATES FORECAST

A. Forecast Methodology

1. BPA Marketing Plan

The rate projections in this document have been prepared prior to the Draft 1993 BPA Marketing Plan, the implementation of which is almost certain to push BPA away from any set of assumptions employed in this document. Therefore, this document may be thought of as representing the "old" BPA with its products and policies. It can be viewed as a starting point or reference point to measure the impact of the "new" BPA with its Marketing Plan, and the broader undertaking referred to as the Competitiveness Project. Two possible results of these major efforts are tiered rates and the unbundling of power and transmission products and services. If adopted, these changes in BPA products and policies would be reflected in BPA's forecasted rates, and hence a new set of projections would be produced and made available to BPA's customers.

2. Near-Term and Out-Years

Charts 1 and 2 contrast summary results of this forecast from those of the previous forecast made in December 1992. In this time interval, BPA transmission capital programs have declined cumulatively over 10 years by 5.9 percent in nominal dollars and 9.7 percent in constant dollars in view of an average escalation of 3.8 percent for substations, towers, and overhead conductors. DRI

escalation for transmission facilities is down 1 percentage point to 5.1 percent per year. Resulting forecasted total transmission costs are lower by \$233M per year by 2015 on \$1.9B less plant-in-service. Lower interest rates also contribute to the lower long-term cost forecast.

The current forecasting method is primarily a transmission plant forecast. Plant projections come from two sources, separating the forecast into near term and out-years. Near term (1993-2002) plant increments are the sum of BPA's two 10 year capital programs, namely the transmission system development program (TSDP) and system replacements program (SRP). Beyond these programs, plant increments are the sum of theoretical replacements and assumed plant additions. Additions are investments that increase the scale or capacity of the system. No additions are assumed on the Interties in the out-years. Additions are assumed, however, to the main grid and general plant. Average additions in the TSDP are continued in real terms through the last 13 years of the study. No relation between plant additions and load forecasts was discovered or assumed.

BPA's transmission development and replacements programs are presented by project and segment below in Tables 18 and 19. Segmented program amounts are major items affecting long-term plant-in-service levels. Other components required to complete the plant forecast include out-year replacements, out-year additions, and retirements of plant throughout the forecast period. As

previously noted, additions are assumed at their average '93-'00 levels in the TSDP. These amounts are \$111M/yr and \$35M/yr (1992\$), respectively, for main grid and general plant.

Replacements and retirements are calculated from generalized industrial survivor curves known as Iowa-type curves. They are computed year-by-year considering all surviving investments from all sources prior to and throughout the forecast period.

3. Segmentation

Whereas power rates development involves Northwest Power Act rate pools, wheeling rates are based on segmented transmission costs. BPA partitions its transmission system into nine segments: Generation-Integration, Network, Fringe, Southern, Northern, and Eastern Interties, and three delivery segments. General wheeling rates provide services over the Network and the three Interties. This forecast segments items into these four segments plus Other Main Grid to capture the entire primary system. General plant levels are forecast as an additional investment item. Associated general plant A&I carrying costs are rolled into the five commercial segments' direct revenue requirements. AC Intertie costs are identified within the PSW Intertie in order to estimate annual payments from NFP and the expected value of AC Intertie replacements, also covered under NFP. Items segmented include plant levels, O&M, revenue credits, and sales.

Depreciation and O&M costs are forecast directly by segment. Interest costs are forecast for the FCRTS as a whole and segmented on the basis of net plant-in-service. Depreciation is forecast on a straight-line basis using 33 years for lines and 56 year economic lives for substations. These economic lives are adjusted for salvage value which is negative for lines accounting for their relatively short economic life. O&M is forecast by segment based on historic labor ratios of O&M costs to plant levels. Methods for segmenting replacements and retirements which are forecast by FERC account are developed in order to estimate segmented plant levels necessary for determining and segmenting transmission costs.

Replacements are segmented in the near term like the SRP (accounting for the zeroes in Table 10 on the Northern and Eastern Interties in the near term); in the out-years, replacements are segmented like the investment in the segments adjusted for age (position) on the Iowa curves. Main grid replacements are separated between Network and Other Main Grid like the overall SRP.

Retirements of plant from service are segmented throughout the forecast period based on segment investments when an item was constructed. Prior to the construction of the Interties, retirements are considered reductions to the main grid and separated between Network and Other Main Grid like cumulative investments.

Retirements of investments in the Interties are computed separately in view of the timing of historical and programmatic

investments in these segments. Retirements of out-year additions to the main grid and theoretical replacements to the entire system including the Interties are computed separately for Interties and main grid. Again, Network retirements are broken-out from the main grid in view of cumulative investments. Lastly, out-year main grid additions are separated between Network or Other Main Grid like the overall segmentation of the TSDP.

4. General Layout and Other BPA Models

The Long-Term Transmission Rates Model (LTTRM) is BPA's wheeling rates forecasting model. This model forecasts plant and O&M amounts necessary for developing rates and uses forecasts of costs and sales produced in other models. Figure 2 below shows the procedures for developing long-term total and segmented costs and wheeling rates. It is a simplified flow diagram of the LTTRM emphasizing relationships to long-term power rates development in BPA's SPM. Transmission plant and O&M forecasts from Steps 1 and 4 are used in the SPM in developing overall transmission costs. The Step 1 plant forecast includes 50 years of associated replacements suitable for repayment-type carrying charge calculations which are performed in the SPM. The sum of annual costs developed in Step 4 and capital cost from the SPM in view of the Step 1 plant forecast plus planned net transmission revenues from Financial Management comprise all the costs of the FCRTS. These costs minus wheeling revenues from Step 8, following

wheeling rates development, are used in the SPM to determine the transmission components of power rates.

SPM is the source of Federal loads for energy classes of service including Priority Firm, Industrial Power, and New Resources.

SPM is also the source of FBS generation costs necessary for functionalizing nonfirm power revenues to the Network. BPA's Nonfirm Revenue Analysis Program (NFRAP) forecasts BPA Nonfirm (NF) sales and total spot-market activity including wheeling to the PSW.

Figure 2
LTTRM General Layout

Success in forecasting long-term costs depends on the quality of the plant forecast and on the establishment of valid relations between plant levels and O&M costs. Because these forecasts are contributions of the LTTRM, the methods employed in forecasting plant and O&M are discussed.

5. Closer Look at Plant and O&M Forecast Methods

As noted above, theoretical replacements and retirements are used in forecasting long-term plant levels. They are calculated here from statistical or generalized renewal rates known as Iowa-type curves.

Property renewal rates are (were) developed by the Engineering Research Institute of Iowa State University. Application of the Iowa curves to forecast replacements requires five items:

- a. all previous investment amounts (increments to plant)
- b. known or assumed Iowa curve structure of increments
- c. Iowa curves
- d. all previous and forecast prices
- e. economic part lives

From which the following sequence may be produced:

Where total placements of plant in forecast year t is the sum of the replacements of all surviving investments from year 1 to $t-1$, the additions in year t , plus the replacement of those additions.

The above sequence is essentially the procedure followed in developing replacements for BPA's transmission repayment study, except that the LTTRM uses theoretical rather than actual retirements of historical investments. The reasonableness of the results depends at its weakest point on the correctness of the FERC account-Iowa curve association.

Figure 3
BPA FERC Account - Iowa Curve Association
Source: WP-93-FS-BPA-02A, p315

	<i>Survivor Curve Type</i>	<i>FERC Account Number</i>	<i>Weight</i>	<i>Average Service Life</i>	<i>Description</i>
			(%)	(Yrs)	
<i>Stations</i>	<i>r2</i>	352	3.10	90	structures and improvements
	<i>s0</i>	353	31.43	37	station equipment
<i>Lines</i>	<i>r3</i>	354	23.44	100	towers and fixtures
	<i>r3</i>	355	2.33	39	poles and fixtures
	<i>r3</i>	356	25.29	100	overhead conductors
	<i>r5</i>	358	0.30	25	underground conductors
<i>General</i>	<i>l1</i>	390	1.73	65	other structures and improvements
	<i>r2</i>	391.1	0.12	12	office furniture; bookcases
	<i>r2</i>	391.2	0.86	13	office furniture; data processing equip.
	<i>l1</i>	392.1	0.34	12	transportation equipment rolling stock
	<i>r5</i>	392.2	0.05	15	helicopters
	<i>r3</i>	392.3	0.11	15	fixed wing aircraft
	<i>l2</i>	393	0.07	18	stores equipment
	<i>l0</i>	394	0.18	18	tools
	<i>l2</i>	395	0.77	22	lab equipment
	<i>r2</i>	396	0.55	15	power operated equipment
	<i>s1</i>	397	3.74	20	communication equipment

Does (and will) FERC account 353, substation equipment, really retire in a manner depicted by a symmetrical type s0 curve? BPA

engineers and accountants make these associations in depreciation studies. Figure 3 shows the Iowa curve structure assumed for all forecasted plant investments. Historical investments are weighted according to actual experience. The weights in Figure 3 reflect BPA's structure at the end of FY 1992. Lifetimes are also those used in BPA's transmission repayment study. They agree with BPA's latest depreciation study (October 1989) except the latter recommends 44 years for towers and fixtures and 46 years for account 356 overhead conductors (100 years is used in this forecast). Table 10 shows segmented theoretical replacements. The last column is the total (minus 13.7 percent of general plant) of BPA's 10 year SRP actually used in the near term forecast of plant levels. The segmentation of the theoretical numbers reflects the segmentation that is contained in the SRP in the near term and the method described above in the out-years. Table 11 shows the completed plant forecast.

BPA transmission O&M is forecast as the product of labor ratios of 1995 segmented O&M to 1995 plant levels in 1990 dollars times forecasted amounts also expressed in 1990 dollars. Transmission construction cost escalation is removed from the plant estimates in

Figure 4
BPA Transmission O&M

<i>Base-Year Segmented Line & Station O&M (1995)</i>	→	<i>Base Year Line and Station O&M Expressed as Ratio of Constant Dollar Plant</i>	×	<i>Forecasted Constant Dollar Plant- in-Service Levels</i>	×	<i>Current/Base DRI Transmission O&M Prices, Labor Productivity (Indices)</i>	=	<i>Forecast BPA Segmented Line & Station O&M</i>
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order to clear the way for the use of transmission O&M price projections. The components of the O&M forecast appear in Figure 4. The fourth term includes DRI forecasts of transmission O&M escalation (stations, towers, and overhead conductors) and a measure of labor productivity increases based on national estimates for all nonfarm employment. Table 12 shows the forecast of costs including O&M amounts.

6. NFP Credits

The 725 MW of AC PSW Intertie is assumed sold prior to 1996 at a price of \$215/kW. In addition, owners pay their 21 percent share (725 MW/3450 MW) of AC Intertie operating costs including O&M, general plant, and replacements. The 1/45th of upfront payments is credited to the PSW Intertie towards depreciation. Interest costs are credited by assuming an 8.4 percent interest savings on the \$156M upfront payment. Since owners reimburse BPA for replacements, the interest credit is depreciated over time reflecting a declining unrecovered investment amount. Additionally, FCRTS-wide interest costs are segmented excluding the depreciated payments from both the PSW Intertie and FCRTS net plant totals.

Table 13 shows revenue credits to the Southern Intertie from all sources including NFP. Cost components of the Annual Cost (AC) rate for NFP are shown computed as credits to this segment. These include 21% of AC intertie-related O&M expenses, along

with carrying charges for general plant and replacements. The annualized cost of replacements (Table 13, Column (E) is from BPA's perspective for purposes of crediting segment costs. These amounts and hence the unit costs shown in Column (H) may not reflect the costs to the participants depending on their collective costs of capital.

7. Loads and Sales

Demand and energy amounts are calibrated to the 1993 rate case forecasts for FY 1995. BPA's original 800 MW PSW Intertie assured delivery limit under the IAP is assumed sold by 2005. Network demand and energy growth for system load purposes (i.e., in addition to PSW Intertie deliveries) is based on 50 percent of the overall regional-Federal peak and energy load projections from the *1992 Pacific Northwest Loads and Resources Study*. Published projections are assumed to understate programmatic conservation by about one-half of the load growth shown. Network wheeling demands as a result are projected to grow around 1 percent per year. This growth nonetheless outstrips Federal load projections from SPM on a coincidental peak basis. The share of Network costs to firm wheeling is projected to increase from 35 percent in 1995 to 40 percent by 2015.

BPA's firm use of the PSW Intertie reflects long-term marketing assumptions; new firm wheeling to the PSW assumes a 25 percent load factor. Nonfirm sales PSW for BPA and wheeling and Intertie

North sales are from NFRAP projections. Lost sales due to Idaho's Southwest Intertie Project (SWIP) and NFP are estimated from historical sales patterns. They are shown as impacting nonfirm sales only. Tables 14 and 15 show the Network and PSW Intertie sales levels used in the forecast of these rates.

B. Data and Assumptions

("Source" refers to Revenue Requirement Documentation, WP-93-FS-BPA02A.)

1. Plant-Related Data

- FY 1995 congressional budget Transmission System Development Program (TSDP), June, 1993, as loaded by Financial Management and segmented and separated between lines and stations by Engineering; covers years 1993 through 2002
- System Replacement Program (SRP), June, 1993, covering BPA system replacements
- 1940-1992 FERC account breakout of transmission investments.
- Average service lives and overall FERC account weights of BPA embedded plant as of September 30, 1992. Also Iowa curve association of the FERC accounts (source: p315).
- Historic plant increments, 1940-1992 (source: pp243-44).
- Economic lives for depreciation purposes (source: p125).
- The Iowa curves: *Statistical Analysis of Industrial Property Retirements*, Iowa State University, Bulletin 125, Table 22, Total Renewals in Percent for Type Curves, 1967.
- *Data Resource Incorporated's (DRI) Pacific Region plant costs indexes for: (1) transmission towers; (2) substations (3) overhead conductors; and (4) the producer price index used for transmission general plant, historic and projected as of Summer 1992 Long-Term Review.*
- Study showing BPA general plant costs increasing similar to DRI's producer price index except 1.011 percent faster.

- 13.7 percent of program (TSD & SRP) general plant is functionalized to generation based on 1992-1995 averages.

2. O&M Data

- Latest forecast of segmented labor ratios, lines and stations, of BPA O&M to FCRTS plant-in-service; similar to source, (p29 and p33) for FY 1995.
- Latest Corp/Bureau O&M, wheeling budget, and R&D amounts (source: p31) for FY 1995.
- DRI Transmission O&M escalation forecast.
- DRI Nonfarm labor productivity forecast.
- Separate breakout of AC vs. DC PSW Intertie O&M ratios using FY 1989-FY 1991 averages.

3. Sales Bases

- SPM forecast for Priority Firm, Industrial Power, Surplus Power, and New Resources.
- Historic Federal and regional net peak resource levels from *1992 Pacific Northwest Loads and Resources Study*.
- From the same study, projected minimum monthly Capacity Surpluses and Deficits for the forecast period.
- Also from this study, regional and Federal system energy forecasts for total system loads.
- Latest Network coincidence factors for 1993 rate case: RAM LRBC01 and LRBT05.
- NFRAP forecast of BPA PSW Nonfirm and nonfirm ISA wheeling
- Latest benchmark estimates of IR, ET, IN, and ISB wheeling

4. Plant Level Assumption

- No out-year additions to the Interties; all out-year additions are to the main grid and general plant.
- All plant increments have the same FERC account structure as total system at the last point in history September 30, 1992.
- Economic lives of Iowa curve parts constant from 1940 throughout the forecast.
- Main grid and general plant additions in the out-years at the average level of the 10 year programs (minus theoretical replacements): \$110.7M main-grid and \$34.9M general plant, 1992\$.
- Corp and Bureau maintain constant share of FCRTS.
- General plant escalates 1.011 percent faster than DRI's Producer Price Index.
- No reduction in plant levels for NFP, except for interest segmentation purposes.

5. Segmentation Assumptions

- Theoretical replacements segmented in the near term like the SRP.
- In the out-years, replacements are segmented considering: the size (cost) of the segment, lines vs. stations, and the segment's age measured by the segments' position on the Iowa curves.
- Interties--PSW AC, PSW DC, Northern, & Eastern--lines and stations are retired from a separate application of the Iowa curves to their historic, programmatic, and replacement investments.
- Main grid additions segmented between Network and Other like the overall TSDP.
- Main grid replacements and retirements segmented between Network and Other like overall SRP.

6. O&M Assumptions

- An increase in PSW DC O&M in 2003, 2004, and 2005 estimated as the impact of an additional \$195M plant item (change-out of the mercury arc valves) spread over three years. Modeled through O&M rather than plant for ease of modeling purposes.
- Corp and Bureau O&M grows 2 percent/year real.
- BPA's wheeling budget grows 3 percent/year real.
- BPA's R&D shows no real growth.
- BPA's wheeling budget consists of 25 percent variable costs subject to escalation.
- Remedial Action Scheme (RAS) on the PSW AC is 15% variable costs which escalate like transmission O&M.

7. Sales Demands Assumptions

- PSW IAP 800MW assured delivery sold by 2005.
- No increases in BPA export power sales from those known and assumed in 1993 rate case for FY 1995.
- 200 MW POWEREX averaging 88MW as in 1993 rate case.
- System-load-based Network demands grow like one-half of the regional-Federal peak load projections in the NW Regional Loads & Resources Study, 1992.

8. Sales Energy Assumptions

- Twenty-five percent load factor on new PSW wheeling contracts.
- Lost IS due to NFP and SWIP is nonfirm in nature and is ramped in over 5 years.
- Lost is due to NFP is based on Puget's and Seattle's historic nonfirm wheeling.

- SWIP assumed energized in 1999.
- New line to Canada in 2005 with minor losses in ET and IN wheeling.
- Lost ET and IS due to SWIP based on portions of adjacent utilities' historic wheeling.

9. Cost of Service Assumptions

- PSW Intertie costs assigned on based of total use in both directions.
- Firm ISB PSW Intertie demand charge set on noncoincidental demands.
- No allocation of Network costs to excess generation capacity.
- NFP direct price of \$215/kW and an instantaneous sale of 725MW completed before FY 1996.
- The 12.3 percent interest rate for TGT revenues.

IV. CHARTS AND TABLES

Chart 2
Industrial Firm Rate Projections
(Real 1993 mills/kWh)

Chart 3
New Resource / Surplus Firm Power Rate Projections
(Real 1993 mills/kWh)

Chart 5
Bonneville Average System Cost Projections
(Real 1993 mills/kWh)

Chart 7
Priority Firm Rates
Historical and Projected
(Real 1993 and Nominal mills/kWh)

Chart 8
Energy Transmission (ET) Rate
Historical and Projected
(Real 1993 and Nominal mills/kWh)

mills/KWh

Chart 9
PSW Intertie Rate (IS-A) Rate
Historical and Projected
(Real 1993 and Nominal mills/kWh)

Table 1
Priority Firm Power Rate
Projected
(Real 1993 and Nominal mills/kWh)

	/----- Real 1993 Mills/kWh -----/			/----- Nominal Mills/kWh -----/		
	Low	Medium	High	Low	Medium	High
1993	23.7	23.7	23.7	23.7	23.7	23.7
1994	26.5	26.5	26.5	27.1	27.1	27.1
1995	25.8	25.8	25.8	27.1	27.1	27.1
1996	25.0	26.7	28.2	26.8	28.7	30.2
1997	25.5	27.7	30.2	28.0	30.4	33.1
1998	25.5	27.8	30.2	28.9	31.5	34.2
1999	26.3	28.7	31.2	30.6	33.4	36.3
2000	26.0	28.7	31.3	31.3	34.5	37.6
2001	25.7	28.7	31.5	31.8	35.5	38.9
2002	24.9	28.4	31.2	31.8	36.3	39.9
2003	25.1	28.9	32.2	33.1	38.0	42.4
2004	23.8	27.8	31.4	32.5	38.0	43.0
2005	23.1	27.3	31.0	32.7	38.7	43.9
2006	23.2	27.5	31.9	33.9	40.3	46.8
2007	23.1	27.4	32.6	35.0	41.5	49.3
2008	23.2	27.6	32.6	36.5	43.3	51.3
2009	23.1	27.6	33.0	37.4	44.7	53.5
2010	23.7	28.5	34.3	39.8	47.7	57.6
2011	24.2	28.9	36.5	41.9	50.0	63.3
2012	23.7	28.1	36.0	42.7	50.6	64.8
2013	23.6	27.9	36.1	43.9	51.8	67.0
2014	24.2	28.2	37.4	46.5	54.1	71.9

Table 2
Industrial Firm Power Rate
Projected
(Real 1993 and Nominal mills/kWh)

	/----- Real 1993 Mills/kWh -----/			/----- Nominal Mills/kWh -----/		
	Low	Medium	High	Low	Medium	High
1993	23.3	23.3	23.3	23.3	23.3	23.3
1994	25.9	25.9	25.9	26.5	26.5	26.5
1995	25.3	25.3	25.3	26.5	26.5	26.5
1996	23.9	25.5	26.9	25.7	27.4	28.8
1997	24.4	26.4	28.7	26.8	29.0	31.5
1998	24.4	26.6	28.8	27.6	30.0	32.6
1999	25.1	27.4	29.8	29.2	31.9	34.6
2000	24.8	27.4	29.8	29.9	32.9	35.8
2001	24.6	27.4	30.0	30.4	33.9	37.1
2002	23.8	27.1	29.7	30.4	34.6	38.0
2003	24.0	27.5	30.6	31.6	36.3	40.4
2004	22.8	26.5	29.9	31.1	36.2	40.9
2005	22.1	26.1	29.6	31.3	36.9	41.9
2006	22.2	26.3	30.4	32.5	38.5	44.6
2007	22.2	26.2	31.0	33.5	39.6	47.0
2008	22.2	26.3	31.0	34.9	41.3	48.8
2009	22.1	26.3	31.4	35.8	42.6	50.9
2010	22.7	27.1	32.7	38.1	45.5	54.8
2011	23.1	27.5	34.7	40.1	47.7	60.1
2012	22.7	26.8	34.2	40.8	48.2	61.6
2013	22.6	26.6	34.3	42.0	49.4	63.6
2014	23.1	26.9	35.5	44.5	51.6	68.2

Table 3
New Resource/Surplus Firm Power Rate
Projected
(Real 1993 and Nominal mills/kWh)

	/----- Real 1993 Mills/kWh -----/			/----- Nominal Mills/kWh -----/		
	Low	Medium	High	Low	Medium	High
1993	33.0	33.0	33.0	33.0	33.0	33.0
1994	35.2	35.2	35.2	36.1	36.1	36.1
1995	34.4	34.4	34.4	36.1	36.1	36.1
1996	40.4	39.7	39.4	43.3	42.6	42.2
1997	41.0	41.2	41.6	45.0	45.2	45.7
1998	41.8	42.3	42.4	47.2	47.8	47.9
1999	42.4	43.5	43.7	49.3	50.6	50.9
2000	42.3	43.8	44.1	50.9	52.7	53.0
2001	42.7	44.3	44.9	52.8	54.7	55.5
2002	42.9	45.1	46.0	54.8	57.6	58.7
2003	42.8	45.5	47.0	56.4	59.9	62.0
2004	41.7	45.0	46.9	57.0	61.5	64.1
2005	41.3	45.2	47.1	58.5	64.0	66.7
2006	41.5	46.1	50.3	60.8	67.6	73.7
2007	41.4	46.2	52.0	62.7	69.9	78.8
2008	41.7	46.9	52.4	65.5	73.6	82.4
2009	42.3	47.7	53.6	68.6	77.3	86.8
2010	43.5	49.5	57.6	73.0	83.0	96.7
2011	44.1	51.3	66.0	76.4	88.9	114.3
2012	44.1	51.1	65.9	79.3	91.9	118.6
2013	44.4	51.5	67.5	82.5	95.7	125.3
2014	45.4	52.1	67.5	87.2	100.1	129.8

Table 4
Average Cost of Nonfirm Energy
Projected
(Real 1993 and Nominal mills/kWh)

	/----- Real 1993 Mills/kWh -----/			/----- Nominal Mills/kWh -----/		
	Low	Medium	High	Low	Medium	High
1993	19.0	19.0	19.0	19.0	19.0	19.0
1994	21.9	21.9	21.9	22.4	22.4	22.4
1995	21.4	21.4	21.4	22.4	22.4	22.4
1996	20.5	22.8	25.4	22.0	24.4	27.2
1997	21.1	23.3	25.9	23.2	25.6	28.4
1998	21.4	23.5	26.0	24.1	26.5	29.4
1999	22.2	24.3	26.9	25.8	28.3	31.2
2000	22.2	24.2	26.7	26.7	29.2	32.2
2001	22.0	24.0	26.5	27.2	29.7	32.8
2002	21.3	23.3	25.9	27.3	29.7	33.1
2003	21.8	23.7	27.1	28.8	31.3	35.7
2004	20.6	22.3	25.7	28.2	30.5	35.1
2005	20.0	21.7	25.0	28.3	30.7	35.4
2006	19.9	21.5	25.7	29.2	31.6	37.7
2007	19.8	21.3	26.3	29.9	32.3	39.8
2008	19.6	21.2	26.2	30.9	33.3	41.2
2009	19.2	20.8	26.0	31.2	33.7	42.2
2010	19.3	21.0	26.9	32.4	35.3	45.2
2011	19.3	22.0	29.3	33.5	38.2	50.7
2012	18.5	21.2	28.4	33.3	38.1	51.2
2013	18.0	20.8	28.8	33.5	38.7	53.4
2014	18.0	20.8	29.7	34.7	40.1	57.1

Table 5
BPA Average System Cost
Projected
(Real 1993 and Nominal mills/kWh)

	/----- Real 1993 Mills/kWh -----/			/----- Nominal Mills/kWh -----/		
	Low	Medium	High	Low	Medium	High
1993	25.1	25.1	25.1	25.1	25.1	25.1
1994	27.6	27.6	27.6	28.3	28.3	28.3
1995	27.0	27.0	27.0	28.3	28.3	28.3
1996	26.2	28.1	30.3	28.1	30.2	32.5
1997	26.7	28.7	30.8	29.3	31.5	33.8
1998	27.0	29.0	31.0	30.5	32.8	35.0
1999	27.9	30.0	32.1	32.4	34.9	37.3
2000	27.9	30.2	32.2	33.6	36.3	38.7
2001	28.1	30.3	32.5	34.7	37.4	40.2
2002	27.7	30.1	32.3	35.4	38.4	41.2
2003	28.2	30.6	33.2	37.1	40.3	43.8
2004	27.3	29.7	32.7	37.4	40.6	44.7
2005	26.9	29.4	32.4	38.1	41.6	45.9
2006	26.9	29.5	33.3	39.4	43.2	48.7
2007	26.9	29.4	33.8	40.7	44.5	51.2
2008	26.9	29.5	33.9	42.3	46.3	53.3
2009	26.7	29.3	34.4	43.3	47.5	55.6
2010	27.2	30.2	35.7	45.6	50.6	59.8
2011	27.4	30.7	37.5	47.5	53.2	65.0
2012	26.8	29.9	37.2	48.3	53.9	66.9
2013	26.6	29.8	37.3	49.4	55.4	69.3
2014	26.9	30.0	38.5	51.8	57.7	74.0

Table 6
BPA Historical Average Power Rates 1/
(Nominal Mills/kWh)

	<u>Priority Firm</u>	<u>Industrial Firm</u>	<u>NonFirm</u>		<u>Priority Firm</u>	<u>Industrial Firm</u>	<u>NonFirm</u>
1940	5.2	2.1	2.5	1967	3.1	2.1	2.1
1941	5.5	2.1	2.6	1968	3.1	2.1	2.0
1942	3.8	2.2	2.5	1969	3.2	2.2	2.0
1943	3.7	2.3	2.5	1970	3.1	2.1	2.0
1944	3.6	2.4	2.5	1971	3.1	2.1	2.0
1945	3.3	3.1	2.5	1972	3.2	2.1	2.0
1946	3.3	2.4	2.5	1973	3.1	2.2	2.1
1947	3.3	2.2	2.5	1974	3.2	2.1	2.0
1948	3.2	2.1	2.5	1975	3.7	3.0	3.3
1949	3.2	2.2	2.5	1976	3.7	3.2	3.4
1950	3.2	2.2	2.5	1977	3.7	2.2	3.1
1951	3.2	2.1	2.5	1978	3.7	2.7	3.3
1952	3.2	2.1	2.5	1979	3.8	3.0	3.0
1953	3.2	2.1	2.5	1980	7.3	5.1	6.5
1954	3.2	2.1	2.5	1981	8.9	7.5	7.8
1955	3.1	2.1	2.5	1982	13.1	19.3	8.0
1956	3.1	2.1	2.5	1983	19.4	24.5	9.8
1957	3.2	2.1	2.5	1984	22.2	25.3	11.3
1958	3.1	2.1	2.5	1985	21.9	20.2	18.0
1959	3.1	2.2	2.5	1986	22.0	20.2	10.5
1960	3.1	2.1	2.5	1987	21.7	24.2	14.1
1961	3.1	2.2	2.5	1988	22.5	23.2	17.3
1962	3.1	2.2	2.5	1989	22.6	23.5	15.2
1963	3.1	2.2	2.5	1990	22.6	23.4	17.0
1964	3.0	2.1	2.5	1991	22.7	23.0	12.8
1965	3.1	2.1	2.5	1992	23.0	23.0	15.1
1966	3.1	2.1	2.1				

1/ Source: BPA Fiscal Year Generation and Sales Statistics.

Table 7
BPA Historical Average Power Rates 1/
(Real \$1993 Mills/kWh)

	<u>Priority Firm</u>	<u>Industrial Firm</u>	<u>NonFirm</u>		<u>Priority Firm</u>	<u>Industrial Firm</u>	<u>NonFirm</u>
1940	36.2	25.2	27.5	1967	12.3	8.3	8.3
1941	34.0	23.8	25.8	1968	11.8	8.3	8.0
1942	32.1	23.3	24.3	1969	11.2	7.9	7.2
1943	31.2	21.7	23.7	1970	10.9	7.5	7.2
1944	30.9	21.4	23.4	1971	9.9	6.8	6.5
1945	29.9	21.7	22.8	1972	9.7	6.5	6.0
1946	24.3	17.6	18.3	1973	9.2	6.0	6.0
1947	21.3	14.1	16.1	1974	8.2	5.5	5.2
1948	19.4	12.7	15.2	1975	8.9	5.9	7.9
1949	19.5	13.3	15.2	1976	8.4	7.1	7.7
1950	19.2	13.1	15.0	1977	7.7	5.2	5.6
1951	18.1	12.0	14.1	1978	7.4	4.7	6.6
1952	17.8	11.8	13.9	1979	6.8	5.2	5.4
1953	17.6	11.6	13.7	1980	10.7	7.7	10.6
1954	17.3	11.4	13.5	1981	11.9	9.1	11.3
1955	16.3	11.1	13.1	1982	16.3	23.0	10.6
1956	15.8	10.7	12.7	1983	25.0	32.9	13.7
1957	15.7	10.4	12.3	1984	29.0	34.5	15.1
1958	15.0	10.0	12.0	1985	28.4	27.3	23.2
1959	14.6	10.4	11.8	1986	27.5	24.4	13.2
1960	14.2	10.1	11.6	1987	25.7	29.1	17.0
1961	14.1	10.0	11.5	1988	26.5	27.3	20.3
1962	13.8	9.8	11.2	1989	25.6	26.2	17.1
1963	13.6	9.6	11.1	1990	24.5	25.6	18.2
1964	13.4	9.1	10.9	1991	24.5	24.7	13.4
1965	13.0	8.8	10.6	1992	23.6	23.6	15.5
1966	12.6	8.5	8.9				

1/ Source: BPA Fiscal Year Generation and Sales Statistics

Table 8
GDP Implicit Price Deflator 1/

	<u>Index</u>	<u>% Change</u>		<u>Index</u>	<u>% Change</u>
1980	.71	9.23	1999	1.43	2.88
1981	.77	8.45	2000	1.48	3.50
1982	.83	7.79	2001	1.52	2.70
1983	.86	3.61	2002	1.57	3.29
1984	.90	4.65	2003	1.62	3.18
1985	.93	3.33	2004	1.68	3.70
1986	.96	3.23	2005	1.74	3.57
1987	.99	3.13	2006	1.80	3.45
1988	1.03	4.04	2007	1.86	3.33
1989	1.08	4.85	2008	1.93	3.76
1990	1.12	3.70	2009	1.99	3.11
1991	1.17	4.46	2010	2.06	3.52
1992	1.20	2.56	2011	2.13	3.40
1993	1.23	2.50	2012	2.21	3.76
1994	1.26	2.44	2013	2.28	3.17
1995	1.29	2.38	2014	2.36	3.51
1996	1.32	2.33	2015	2.45	3.81
1997	1.35	2.27	2016	2.53	3.27
1998	1.39	2.96	2017	2.62	3.56

1/ DRI Utility Cost Information Service, Summer 1993 (FY 1987 = 1.0 index)

Table 9
PF Demand And Energy Charge 1/

	PF Growth	Demand Charge	Summer Energy Charge	Winter Energy Charge
	(%)	(\$/kW-mo) <u>2/</u>	(mills/kWh) <u>2/</u>	(mills/kWh) <u>2/</u>
1994	---	4.14	16.29	22.17
1995	---	4.14	16.29	22.17
1996	5.51	4.37	17.19	23.39
1997	5.92	4.63	18.21	24.78
1998	3.62	4.80	18.87	25.67
1999	6.03	5.08	20.00	27.22
2000	3.29	5.25	20.66	28.12
2001	2.90	5.40	21.26	28.94
2002	2.25	5.53	21.74	29.59
2003	4.68	5.79	22.76	30.97
2004	0.00	5.79	22.76	30.97
2005	1.84	5.89	23.18	31.54
2006	4.13	6.14	24.14	32.85
2007	2.98	6.32	24.85	33.83
2008	4.34	6.59	25.93	35.29
2009	3.23	6.81	26.77	36.43
2010	6.71	7.26	28.57	38.88
2011	4.82	7.61	29.94	40.75
2012	1.20	7.70	30.30	41.24
2013	2.37	7.89	31.02	42.22
2014	4.44	8.24	32.40	44.10
2015	4.44	8.60	33.84	46.05

1/ The Supply Pricing Model is an energy only model and does not forecast separate PF demand and energy charges. The changes in this table are computed outside the Supply Pricing Model and assumes that the relationship between demand and energy charges calculated in the 1993 Rate Filing will continue into the future.

2/ The forecasted demand and energy charges were derived by multiplying the year to year growth in the medium PF rate projection (Table 2) times the demand and energy charges in BPA's PF-93 rate schedule.

Table 10
Base-Case Theoretical Replacements
(\$000, Nominal Plant Amounts)

	(A) Network 2/	(B) PSW DC 2/	(C) PSW AC 2/	(D) Northern Intertie 2/	(E) Eastern Intertie 2/	(F) Other Main Grid 2/	(G) General	(H) Total 1/ Theoretical	(I) '94 SRP 3/
1993	\$31,216	\$4,079	\$1,716	\$0	\$0	\$8,354	\$7,339	\$52,704	\$142,095
1994	\$33,184	\$4,107	\$1,779	\$0	\$0	\$8,744	\$7,551	\$55,365	\$94,007
1995	\$34,127	\$4,645	\$1,978	\$0	\$0	\$9,435	\$7,912	\$58,097	\$83,928
1996	\$36,832	\$4,809	\$2,053	\$0	\$0	\$9,939	\$8,173	\$61,806	\$86,296
1997	\$38,566	\$5,228	\$2,231	\$0	\$0	\$10,649	\$8,600	\$65,274	\$96,211
1998	\$40,712	\$5,401	\$2,300	\$0	\$0	\$11,077	\$8,981	\$68,471	\$88,142
1999	\$42,580	\$5,670	\$2,421	\$0	\$0	\$11,630	\$9,593	\$71,894	\$92,612
2000	\$44,708	\$5,994	\$2,553	\$0	\$0	\$12,247	\$10,066	\$75,568	\$98,017
2001	\$47,072	\$6,257	\$2,677	\$0	\$0	\$12,863	\$10,739	\$79,608	\$102,744
2002	\$49,197	\$6,517	\$2,793	\$0	\$0	\$13,425	\$11,286	\$83,218	\$108,308
2003	\$52,967	\$3,994	\$3,937	\$181	\$378	\$14,186	\$12,090	\$87,733	
2004	\$54,996	\$4,029	\$4,879	\$232	\$537	\$14,691	\$12,865	\$92,229	
2005	\$57,118	\$4,618	\$5,223	\$233	\$542	\$15,222	\$13,869	\$96,825	
2006	\$60,276	\$4,882	\$5,521	\$265	\$573	\$15,913	\$14,708	\$102,138	
2007	\$63,284	\$4,957	\$6,476	\$288	\$630	\$16,631	\$15,691	\$107,957	
2008	\$66,904	\$5,044	\$6,729	\$296	\$714	\$17,504	\$16,510	\$113,701	
2009	\$69,357	\$5,656	\$7,115	\$347	\$849	\$18,141	\$17,506	\$118,971	
2010	\$73,327	\$5,728	\$7,340	\$409	\$877	\$19,029	\$18,442	\$125,152	
2011	\$77,434	\$5,802	\$8,294	\$424	\$941	\$19,897	\$19,532	\$132,324	
2012	\$81,513	\$6,400	\$8,531	\$488	\$1,015	\$20,791	\$20,581	\$139,319	
2013	\$86,408	\$6,495	\$8,679	\$508	\$1,054	\$21,820	\$21,788	\$146,752	
2014	\$91,034	\$6,589	\$8,805	\$857	\$1,198	\$22,843	\$22,913	\$154,239	
2015	\$95,601	\$6,723	\$9,991	\$881	\$1,258	\$23,822	\$24,153	\$162,429	

- 1/ Assumes 100 year lives for towers, fixtures, and overhead conductors to be consistent with replacement calculations in BPA's repayment study. Depreciation studies suggest 44 and 46 years for these items.
- 2/ Segmented like BPA's System Replacement Program (SRP) through 2002.
- 3/ Excludes 13.7% of general plant amounts assumed functionalized to generation. See Table 19 for details of the SRP.

Table 1.1
Base-Case Completed Plant-In-Service 1/
(\$M, Nominal)

	(A) Network	(B) PSW DC	(C) PSW AC	(E) Northern Intertie	(F) Eastern Intertie	(G) Other Main Grid	(H) General	(I) Total 2/ FCRTS
1995	\$2,480	\$317	\$430	\$34	\$124	\$631	\$660	\$4,676
1996	\$2,559	\$320	\$443	\$34	\$123	\$652	\$695	\$4,828
1997	\$2,625	\$324	\$454	\$44	\$123	\$671	\$687	\$4,927
1998	\$2,731	\$327	\$464	\$54	\$122	\$688	\$678	\$5,064
1999	\$2,948	\$329	\$473	\$54	\$122	\$732	\$668	\$5,325
2000	\$3,160	\$333	\$482	\$102	\$122	\$777	\$657	\$5,633
2001	\$3,338	\$337	\$492	\$150	\$123	\$798	\$645	\$5,883
2002	\$3,581	\$341	\$502	\$151	\$123	\$819	\$632	\$6,149
2003	\$3,795	\$342	\$507	\$152	\$123	\$843	\$649	\$6,411
2004	\$3,976	\$342	\$508	\$152	\$122	\$870	\$698	\$6,668
2005	\$4,165	\$342	\$509	\$152	\$122	\$899	\$749	\$6,937
2006	\$4,362	\$342	\$510	\$152	\$122	\$928	\$803	\$7,218
2007	\$4,568	\$342	\$512	\$152	\$122	\$959	\$859	\$7,514
2008	\$4,784	\$341	\$514	\$152	\$122	\$992	\$918	\$7,823
2009	\$5,010	\$341	\$516	\$152	\$122	\$1,026	\$981	\$8,148
2010	\$5,246	\$342	\$518	\$152	\$122	\$1,062	\$1,047	\$8,489
2011	\$5,495	\$342	\$520	\$152	\$122	\$1,100	\$1,116	\$8,848
2012	\$5,755	\$342	\$523	\$152	\$122	\$1,140	\$1,189	\$9,224
2013	\$6,027	\$343	\$527	\$152	\$123	\$1,181	\$1,266	\$9,618
2014	\$6,312	\$343	\$530	\$153	\$123	\$1,225	\$1,346	\$10,030
2015	\$6,610	\$344	\$533	\$153	\$123	\$1,270	\$1,429	\$10,462

1/ 1995 amounts are 93 rate-case levels less retirements after FY92. Changes in plant levels are the sum of additions and replacements less retirements. In the near-term, investments come from BPA's development (TSD) and replacements (SR) programs; in the out-years, they are the sum of replacements in Table 10 and the average additions to the Network, Other Main Grid, and to General Transmission plant in the TSD. These amounts are \$110.9M/yr for Main Grid and \$34.9M/yr for General transmission plant additions in 1992 dollars.

2/ Average increases in plant levels are \$210M per year in the near-term, and \$332M per year after 2002.

Table 12
Segment Revenue Requirements
(\$M, Nominal)
Base Case

	(A) /----- FCRTS -----/ A&I 1/	(B) O&M 2/	(C) Total	(D) /-----Network-----/ A&I	(E) O&M	(F) Total	(G) /----- PSW 4/ -----/ A&I	(H) O&M 3/	(I) Total	(J) /----- All Other -----/ A&I	(K) O&M	(L) Total
1995	\$340	\$238	\$578	\$203	\$117	\$320	\$70	\$24	\$94	\$67	\$97	\$165
1996	\$378	\$242	\$620	\$225	\$119	\$344	\$78	\$25	\$103	\$75	\$98	\$173
1997	\$396	\$253	\$649	\$235	\$125	\$360	\$81	\$26	\$107	\$80	\$102	\$181
1998	\$398	\$267	\$665	\$239	\$133	\$371	\$80	\$27	\$107	\$80	\$107	\$187
1999	\$438	\$294	\$732	\$270	\$140	\$410	\$82	\$28	\$109	\$86	\$126	\$212
2000	\$446	\$313	\$759	\$276	\$147	\$423	\$78	\$29	\$107	\$92	\$137	\$229
2001	\$475	\$334	\$809	\$295	\$155	\$450	\$79	\$30	\$110	\$100	\$149	\$249
2002	\$502	\$359	\$861	\$320	\$163	\$483	\$80	\$32	\$112	\$102	\$164	\$266
2003	\$519	\$383	\$902	\$337	\$171	\$508	\$80	\$35	\$115	\$102	\$176	\$279
2004	\$547	\$404	\$951	\$360	\$179	\$539	\$81	\$38	\$119	\$106	\$187	\$293
2005	\$571	\$427	\$998	\$381	\$189	\$570	\$81	\$41	\$122	\$109	\$197	\$306
2006	\$579	\$449	\$1,028	\$391	\$198	\$589	\$79	\$43	\$122	\$109	\$208	\$317
2007	\$613	\$473	\$1,086	\$419	\$210	\$629	\$80	\$45	\$125	\$114	\$219	\$332
2008	\$637	\$499	\$1,136	\$441	\$222	\$663	\$80	\$46	\$126	\$116	\$230	\$346
2009	\$627	\$525	\$1,152	\$438	\$235	\$673	\$76	\$48	\$124	\$113	\$242	\$355
2010	\$688	\$552	\$1,240	\$486	\$248	\$734	\$79	\$50	\$129	\$122	\$254	\$376
2011	\$708	\$582	\$1,290	\$505	\$263	\$769	\$79	\$52	\$130	\$124	\$267	\$391
2012	\$729	\$613	\$1,342	\$525	\$279	\$804	\$78	\$54	\$131	\$126	\$280	\$407
2013	\$775	\$646	\$1,421	\$563	\$296	\$859	\$79	\$56	\$135	\$133	\$294	\$427
2014	\$792	\$681	\$1,473	\$580	\$314	\$894	\$78	\$58	\$136	\$134	\$309	\$443
2015	\$828	\$717	\$1,545	\$612	\$333	\$945	\$78	\$60	\$138	\$138	\$324	\$462

- 1/ Amortization, interest, and planned net revenues are from SPM repayment simulation. A&I is segmented on net plant (net of accumulated depreciation). Amounts include general plant carrying costs.
- 2/ O&M consists mostly of BPA transmission O&M but also includes Corp/Bureau O&M, BPA wheeling budget, and R&D amounts. The BPA O&M forecast is developed as a function of real plant levels wherein ratios of O&M to plant are adjusted for changes in plant prices, labor productivity levels, and O&M escalation.
- 3/ DC O&M amounts are increased in 2003-2005 for change out of the mercury arc valves.
- 4/ Before crediting NFP.

Table 13
PSW Intertie Revenue Credits
Including Generalized Annual Cost Rate Development
(\$000 Nominal)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	/----- NFP AC Rate Development -----/ /----- Replacements -----/ /--- NFP Upfront Payment ---/ Interest 1/ Depreciation							AC Remedial Action Scheme			Total Credits
			O&M	Investment 2/ Annual Costs	Gen. Plant	Subtotal (\$/kW/yr)	Effective AC Rate 3/ AC Rate 3/ AC Rate 3/		Misc. AC and DC		
1995	13,272	3,464	1,357	415	20	1,281	2,658	3.67 4/	732	1,024	18,753
1996	12,973	3,464	1,431	431	67	1,442	2,940	4.06	736	1,044	18,619
1997	12,675	3,464	1,510	469	114	1,436	3,060	4.22	741	1,066	18,320
1998	12,377	3,464	1,585	483	166	1,334	3,085	4.26	745	1,086	17,924
1999	12,079	3,464	1,645	508	214	1,265	3,124	4.31	749	1,106	17,561
2000	11,781	3,464	1,723	536	271	1,085	3,079	4.25	753	1,128	17,087
2001	11,482	3,464	1,803	562	337	1,011	3,151	4.35	758	1,152	16,719
2002	11,184	3,464	1,882	587	402	927	3,211	4.43	762	1,174	16,341
2003	10,886	3,464	1,952	827	476	912	3,340	4.61	766	1,198	16,033
2004	10,588	3,464	2,022	1,025	577	999	3,598	4.96	771	1,220	15,827
2005	10,289	3,464	2,101	1,097	688	1,073	3,862	5.33	775	1,244	15,606
2006	9,991	3,464	2,179	1,159	785	1,105	4,069	5.61	779	1,268	15,345
2007	9,693	3,464	2,267	1,360	901	1,189	4,357	6.01	784	1,296	15,136
2008	9,395	3,464	2,354	1,413	1,052	1,244	4,650	6.41	789	1,322	14,898
2009	9,096	3,464	2,442	1,494	1,154	1,208	4,804	6.63	793	1,346	14,568
2010	8,798	3,464	2,538	1,541	1,335	1,341	5,214	7.19	798	1,374	14,408
2011	8,500	3,464	2,635	1,742	1,481	1,367	5,483	7.56	802	1,402	14,141
2012	8,202	3,464	2,731	1,792	1,631	1,391	5,753	7.94	807	1,430	13,872
2013	7,903	3,464	2,836	1,823	1,797	1,460	6,093	8.40	811	1,458	13,646
2014	7,605	3,464	2,950	1,849	1,957	1,458	6,365	8.78	816	1,490	13,352
2015	7,307	3,464	3,063	2,098	2,145	1,498	6,706	9.25	821	1,520	13,099

1/ Based on forecasted interest rates times depreciated upfront payments. Nominal payments are \$215/kW on 725 MW. The interest credit is based on unrecovered investment for general consistency with the AC rate which includes replacements.

2/ Source: 21% of Table 10, Col (C).

3/ Assumes replacement costs are financed at BPA's cost of capital. Therefore, amounts are credits per unit of NFP produced from the AC charge.

4/ \$3.90/kW-yr is AC-93 shown in the TRDS, WP-93-FS-BPA05, on page E-2.

Table 14
Network Wheeling Sales

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				/----- Nonfirm 3/ -----/					
	Demands	System Related 1/	NFP 2/ and Asr'd Del	PSW	NWNW	Excess of Demands	IR/ET Bill. Det. 4/	ET Sales	IN Sales 5/
	(MW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)
1995	10,691	4,572	427	779	73	(90)	5,761	795	473
1996	11,002	4,594	536	693	82	(103)	5,802	793	492
1997	11,214	4,726	622	708	87	(109)	6,034	842	528
1998	11,716	4,769	740	734	88	(110)	6,220	852	526
1999	12,193	4,820	825	754	88	(110)	6,378	852	518
2000	12,267	4,872	846	714	95	(119)	6,407	919	592
2001	12,376	4,914	866	711	95	(120)	6,467	925	599
2002	12,564	4,963	886	714	96	(121)	6,538	933	604
2003	12,626	5,012	907	707	96	(120)	6,601	927	602
2004	12,714	5,058	927	691	96	(120)	6,651	929	610
2005	12,799	5,082	947	688	96	(121)	6,692	929	614
2006	12,916	5,089	947	644	92	(116)	6,657	890	601
2007	12,965	5,118	947	616	91	(115)	6,657	873	603
2008	12,974	5,159	947	609	89	(111)	6,692	840	583
2009	13,033	5,218	947	603	86	(108)	6,746	808	563
2010	13,199	5,249	947	598	85	(106)	6,773	788	555
2011	13,359	5,279	947	593	86	(108)	6,798	800	567
2012	13,392	5,313	947	588	87	(110)	6,826	812	580
2013	13,525	5,329	947	583	89	(111)	6,837	824	594
2014	13,650	5,372	947	578	90	(113)	6,875	836	607
2015	13,717	5,416	947	574	91	(114)	6,913	846	618

-
- 1/ System load related Network loads tied to 1/2 of Whitebook Regional minus Federal median case energy load growth. 1995 amounts are from the 1993 rate case.
- 2/ New Network contracts due to NFP. Table 5 (E) shows assured delivery portion.
- 3/ Source: US portion of NFRAP projection for PSW; historical relations for other concepts.
- 4/ Sum of columns (B) through (F), reflecting total wheeling from customers with firm Network contracts within Transmission Demands excluding imports from Canada.
- 5/ Source: NFRAP projections through 2010.

Table 15
BPA PSW Intertie Activity 1/

	(A) BPA 2/ Intertie Capacity	(B) /-----BPA -----/ Firm 3/	(C) Nonfirm 4/	(D) /----- Wheeling -----/ /-- Asr'd Delivery --/ Demands	(E) Energy	(F) Nonfirm 4/ -----/ US	(G) Canada	(H) Total (B) thru (G)	(I) Lost IS Due to NFP 5/	(J) SWIP 6/
	(MW)	(aMW)	(aMW)	(MW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)	(aMW)
1995	5,715	578	930	730	388	766	219	2,881	0	0
1996	5,715	578	827	737	408	527	230	2,569	155	0
1997	5,715	578	845	744	428	536	251	2,637	161	0
1998	5,715	578	876	751	448	557	249	2,708	165	0
1999	5,715	684	920	758	468	567	238	2,877	170	21
2000	5,715	684	890	765	488	519	274	2,855	174	42
2001	5,715	635	928	771	508	499	264	2,833	179	86
2002	5,715	635	976	778	528	483	252	2,873	187	135
2003	5,715	635	1,013	785	548	459	235	2,889	192	184
2004	5,715	739	1,042	792	568	426	223	2,997	197	236
2005	5,715	739	1,039	799	588	422	231	3,018	197	238
2006	5,715	739	978	799	588	391	232	2,927	189	227
2007	5,715	684	941	799	588	367	247	2,827	186	223
2008	5,715	684	931	799	588	362	248	2,813	184	222
2009	5,715	635	922	799	588	356	249	2,750	183	220
2010	5,715	624	917	799	588	351	257	2,739	184	221
2011	5,715	624	913	799	588	345	266	2,737	185	222
2012	5,715	624	908	799	588	339	275	2,734	186	223
2013	5,715	624	902	799	588	333	284	2,732	187	224
2014	5,715	624	897	799	588	327	293	2,730	187	225
2015	5,715	624	893	799	588	322	300	2,728	188	226

- 1/ Energy amounts are total schedules, including N-S and S-N.
2/ 2990 MW DC plus 4800 MW AC minus 950 MW PGE minus 400 MW PPL minus 725 NFP.
3/ Reflects '93 rate-case numbers for '95 and long-term marketing assumptions thereafter.
4/ Source: NFRAP total spot market sales split between BPA and wheeling from history.
5/ Puget's, Seattle's and Tacoma's 17% share of '93 rate case projections.
6/ SWIP assumed energized in 1999. Varying portions of IPC, MPC, WWP, PPL, and SCL are assumed lost.

Table 16
Forecasted BPA Wheeling Rates
(Nominal Dollars)

	/----- Network -----/			/----- Intertie South -----/			Intertie	/--- Intertie East ---/	
	/----- IR -----/			/----- ISB -----/			North		
	Demand	Energy	ET	Demand	Energy	ISA	IN	TGT	IE
	(\$/kWyr)	(\$/MWh)	(\$/MWh)	(\$/kWyr)	(\$/MWh)	(\$/MWh)	(\$/MWh)	(\$/kWyr)	(\$/MWh)
Current	5.09	1.06	2.02	8.47	1.69	3.11	0.86	7.81	2.04
1996	5.28	1.14	2.19	9.74	1.37	3.79	0.84	7.84	2.05
1997	5.48	1.16	2.23	10.20	1.91	3.87	1.10	7.87	2.06
1998	5.50	1.18	2.26	10.09	1.85	3.74	1.35	7.90	2.07
1999	6.02	1.31	2.51	10.12	1.80	3.65	1.40	7.93	2.07
2000	6.20	1.36	2.60	10.10	1.76	3.57	2.39	7.96	2.08
2001	6.56	1.43	2.75	10.70	1.82	3.70	3.52	8.00	2.09
2002	6.93	1.52	2.92	11.01	1.84	3.73	3.47	8.04	2.10
2003	7.30	1.59	3.06	11.47	1.88	3.81	3.40	8.07	2.11
2004	7.78	1.70	3.25	11.71	1.88	3.83	3.37	8.11	2.12
2005	8.18	1.79	3.42	12.26	1.94	3.94	3.33	8.15	2.13
2006	8.42	1.87	3.57	12.59	1.99	4.05	3.29	8.19	2.14
2007	8.93	1.98	3.79	13.42	2.12	4.31	3.30	8.23	2.15
2008	9.35	2.07	3.94	13.65	2.16	4.39	3.37	8.27	2.16
2009	9.36	2.06	3.92	13.69	2.16	4.39	3.26	8.32	2.18
2010	10.13	2.25	4.28	14.43	2.28	4.64	3.45	8.37	2.19
2011	10.17	2.28	4.33	14.57	2.30	4.68	3.30	8.41	2.20
2012	10.60	2.37	4.51	14.72	2.32	4.72	3.16	8.46	2.21
2013	11.14	2.52	4.78	15.21	2.40	4.88	3.10	8.52	2.23
2014	11.47	2.60	4.94	15.31	2.42	4.91	2.95	8.57	2.24
2015	12.06	2.73	5.20	15.63	2.47	5.02	2.88	8.63	2.26
Level'd 1/	7.803	1.708	3.263	12.316	2.105	4.242	2.552	8.742	2.287
(%/yr) 2/	4.407	4.844	4.841	3.111	1.196	2.423	6.229	0.500	0.513

1/ Levelized using 1993 BPA interest rate of 8.45%.

2/ 1995-2015 average annual growth rate.

Table 17
Forecasted BPA Wheeling Rates
(Real, Late-1993 Constant Dollars)

	/----- Network -----/ /----- IR -----/			/----- Intertie South -----/ /----- ISB -----/			Intertie North	/--- Intertie East ---/ TGT IE	
	Demand	Energy	ET	Demand	Energy	ISA	IN		
	(\$/kWyr)	(\$/MWh)	(\$/MWh)	(\$/kWyr)	(\$/MWh)	(\$/MWh)	(\$/MWh)	(\$/kWyr)	(\$/MWh)
Current	4.870	1.014	1.933	8.104	1.617	2.966	0.823	7.472	1.952
1996	4.929	1.064	2.045	9.093	1.746	3.538	0.784	7.319	1.914
1997	4.977	1.054	2.025	9.264	1.735	3.515	0.999	7.148	1.871
1998	4.829	1.036	1.984	8.859	1.624	3.284	1.185	6.936	1.817
1999	5.081	1.106	2.118	8.541	1.519	3.081	1.182	6.693	1.747
2000	5.030	1.103	2.109	8.193	1.428	2.896	1.939	6.457	1.687
2001	5.099	1.111	2.137	8.317	1.415	2.876	2.736	6.218	1.624
2002	5.185	1.137	2.185	8.238	1.377	2.791	2.596	6.016	1.571
2003	5.251	1.144	2.201	8.250	1.352	2.740	2.446	5.805	1.518
2004	5.380	1.176	2.247	8.097	1.300	2.648	2.330	5.608	1.466
2005	5.424	1.187	2.268	8.130	1.286	2.613	2.208	5.405	1.412
2006	5.337	1.185	2.263	7.980	1.261	2.567	2.085	5.191	1.356
2007	5.413	1.200	2.298	8.135	1.285	2.613	2.000	4.989	1.303
2008	5.413	1.198	2.281	7.902	1.250	2.541	1.951	4.788	1.250
2009	5.179	1.140	2.169	7.575	1.195	2.429	1.804	4.604	1.206
2010	5.351	1.189	2.261	7.623	1.204	2.451	1.823	4.422	1.157
2011	5.119	1.148	2.179	7.334	1.158	2.356	1.661	4.233	1.107
2012	5.076	1.135	2.160	7.048	1.111	2.260	1.513	4.051	1.058
2013	5.068	1.146	2.175	6.919	1.092	2.220	1.410	3.876	1.014
2014	4.966	1.126	2.139	6.628	1.048	2.126	1.277	3.710	0.970
2015	4.968	1.125	2.142	6.439	1.017	2.068	1.186	3.555	0.931
Lvlz'd 1/ (%/yr) 2/	5.282 0.100	1.157 0.521	2.212 0.515	8.294 -1.143	1.412 -2.292	2.845 -1.787	1.742 1.844	5.840 -3.646	1.527 -3.634

1/ Levelized using a 3% real discount rate.

2/ 1995-2015 average annual growth rate.

Table 18
Transmission System Development Program (TSDP)
1993 Rate-Case, June, 1993
(\$M, Nominal Increments to Rate-Base)

PROJECT	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
NETWORK										
SHELTON REINFORCEMENT	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SNOHOMISH CNTY PUD SUPPORT	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SNO-KING TRANSFORMER ADDN.	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CUSTOMER SVC. ITEMS	0.9	0.7	0.8	1.0	0.7	0.8	0.6	0.7	0.8	0.8
MISC. LINES/SUBS ADDITIONS	7.3	6.2	5.8	6.1	6.2	5.8	4.7	4.3	5.5	5.8
WESTERN MONTANA TRANS.	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EUGENE-MEDFORD	1.1	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THIRD AC INTERTIE	2.7	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BOUNDARY INTEGRATION	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PORT ANGELES SYS. ADDN.	4.3	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SYSTEM REACTIVE FAC.	38.2	21.9	18.8	20.7	18.2	16.9	13.7	11.9	15.6	16.4
TAFT-BELL 500 KV REINF.	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SYSTEM CONTROLS	0.6	1.2	1.3	1.2	1.0	1.1	0.8	0.8	1.0	1.1
MISC. COMPLETIONS	0.3	0.4	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
ALBANY TRANSFORMER SUPPORT	0.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LONGVIEW SYSTEM REINF.	0.0	22.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ECHO LAKE REACTIVE STA.	0.0	24.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRANS./SUBS EFFICIENCY	0.0	0.4	3.9	5.4	5.4	5.1	4.7	4.3	5.2	5.5
HUNGRY HORSE LINE RE-BUILD	0.0	0.0	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KITTITAS-PUGET SD. VOLTAGE REI	0.0	0.0	53.0	0.0	0.0	0.0	27.0	0.0	0.0	0.0
SNOHOMISH TRANSFORMER SPT.	0.0	0.0	0.0	0.0	7.8	0.0	0.0	0.0	0.0	0.0
BELLINGHAM AREA REINF.	0.0	0.0	0.0	0.0	20.3	0.0	0.0	0.0	0.0	0.0
GIG HARBOR AREA REINF.	0.0	0.0	0.0	0.0	0.0	15.5	0.0	0.0	0.0	0.0
COLUMBIA FALLS 230-KV ADDN.	0.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	0.0	0.0
NORTH EUGENE SUPPORT	0.0	0.0	0.0	0.0	0.0	4.1	0.0	0.0	0.0	0.0
NW MONTANA/N.IDAHO SPT.	0.0	0.0	0.0	0.0	0.0	61.4	0.0	0.0	0.0	0.0
MOSSY ROCK GENERATION SPT.	0.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0
E. WASHINGTON REINF.	0.0	0.0	0.0	0.0	0.0	0.0	156.9	0.0	0.0	0.0
S.SEATTLE-OLY REINF.	0.0	0.0	0.0	0.0	0.0	0.0	60.6	0.0	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	1.8	1.9
N.SEATTLE TXF. REINF.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.2	0.0	0.0
KING COUNTY SYS. REINF.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.5	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.2	7.8	8.2
OLYMPIC PENIN. REINF.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	14.7
PUGET SOUND REINF.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	155.5	164.3
CHIEF JOSEPH TXF. ADDN.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2	7.5
Subtotal Network	77.2	89.5	88.3	34.5	59.7	113.7	280.8	102.1	214.4	226.3
OTHER MAIN GRID										
SALEM-TILLAMOOK RECOND.	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOLEDO TRANSFORMER REINF.	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CUSTOMER SVC. ITEMS	5.0	4.2	4.5	5.4	4.2	4.8	3.2	4.0	4.4	4.7
MISC. LINES/SUBS ADDITIONS	4.1	3.5	3.3	3.4	3.5	3.3	2.7	2.5	3.1	3.3
MISC. COMPLETIONS	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EAST MINIDOKA SUPPORT	0.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRANS./SUBS EFFICIENCY	0.0	0.1	0.5	0.7	0.7	0.7	0.6	0.6	0.7	0.7
MINIDOKA AREA SERVICE	0.0	0.0	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KLICITAT/SKAMANIA SUPPORT	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRI-CITIES AREA REINF.	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0
GIG HARBOR AREA REINF.	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0
LAGRANDE TRANSFORMER SUPPORT	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	0.0
WELLS AREA SERVICE	0.0	0.0	0.0	0.0	0.0	0.0	51.1	0.0	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7	2.3	2.5
CHEHALIS TRANSFORMER SPT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.4
Subtotal Other Main Grid	12.2	10.4	15.0	12.5	8.4	11.3	57.6	13.8	12.7	13.6

Table 18 (cont.)
Transmission System Development Program (TSDP)
1993 Rate-Case, June, 1993
(\$M, Nominal Increments to Rate-Base)

PROJECT	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SOUTHERN										
EUGENE-MEDFORD	34.0	74.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THIRD AC INTERTIE	73.3	28.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DC TERMINAL EXP.	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SYSTEM REACTIVE FAC.	17.4	10.0	8.6	9.5	8.3	7.7	5.2	5.4	7.1	7.5
SYSTEM CONTROLS	1.8	3.5	3.9	3.6	3.0	3.3	2.4	2.5	3.1	3.3
MISC. COMPLETIONS	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	1.9	2.1
Subtotal Southern Intertie	130.1	116.5	14.1	13.1	11.3	11.0	8.6	13.4	12.1	12.9
NORTHERN										
BELLINGHAM AREA REINF.	0.0	0.0	0.0	0.0	20.2	0.0	0.0	0.0	0.0	0.0
E.CANADIAN INTERTIE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.7	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	1.0	1.1
Subtotal Northern Intertie	0.0	0.0	0.0	0.0	20.2	0.0	0.0	96.6	1.0	1.1
EASTERN										
WESTERN MONTANA TRANS.	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.6	0.6
Subtotal Eastern Intertie	5.1	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.6	0.6
GENERAL										
CUSTOMER SVC. ITEMS	0.4	0.3	0.3	0.4	0.3	0.4	0.2	0.3	0.3	0.4
MISC. LINES/SUBS ADDITIONS	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.3	0.3
EUGENE-MEDFORD	0.4	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
THIRD AC INTERTIE	15.6	6.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SYSTEM REACTIVE FAC.	0.6	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
SYSTEM CONTROLS	17.7	34.6	38.0	35.0	29.6	31.9	23.7	24.8	30.1	31.8
MISCELLANEOUS TSD	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MAJOR NEW BUILDINGS	1.1	6.2	6.6	16.4	14.5	14.2	12.8	14.1	15.4	16.3
EAST MINIDOKA SUPPORT	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KITTITAS-PUGET SD. VOLTAGE REI	0.0	0.0	1.6	0.0	0.0	0.0	0.8	0.0	0.0	0.0
VARIOUS ADDITIONS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.1	0.1
Subtotal General Plant	36.7	49.0	47.2	52.4	45.0	47.0	37.9	40.0	46.4	49.1
Total TSD Program	261.3	265.4	164.6	112.5	144.6	183.0	384.9	267.5	287.2	303.6

Table 19
System Replacements Program (SRP)
1993 Rate-Case, June, 1993
(\$M, Nominal Increments to Rate-Base)

PROJECT	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
NETWORK										
TRANSMISSION LINE REPL.	6.6	1.1	1.1	1.4	1.4	1.5	1.6	1.6	1.8	1.9
SUBSTATION REPLACEMENTS	47.5	20.0	27.6	24.7	31.6	25.3	27.1	29.2	29.8	31.2
SYSTEM PROTECTION REPLACEMENTS	4.9	3.9	2.3	3.1	2.8	2.8	2.8	2.8	3.1	3.3
Subtotal Network	59.0	25.0	31.0	29.2	35.8	29.6	31.5	33.6	34.7	36.4
OTHER MAIN GRID										
TRANSMISSION LINE REPL.	0.7	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
SUBSTATION REPLACEMENTS	16.6	7.0	9.7	8.7	11.1	8.9	9.5	10.2	10.4	10.9
SYSTEM PROTECTION REPLACEMENTS	0.9	0.7	0.4	0.6	0.5	0.5	0.5	0.5	0.6	0.6
Subtotal Other Main Grid	18.2	7.8	10.2	9.4	11.7	9.6	10.2	10.9	11.2	11.7
SOUTHERN										
TRANSMISSION LINE REPL.	0.3	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SUBSTATION REPLACEMENTS	12.7	5.3	7.4	6.6	8.4	6.8	7.2	7.8	7.9	8.3
SYSTEM PROTECTION REPLACEMENTS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Subtotal Southern Intertie	13.1	5.4	7.5	6.8	8.6	7.0	7.4	8.0	8.1	8.5
NORTHERN EASTERN										
GENERAL										
NON-ELECTRIC PLANT REPL.	14.9	31.2	7.3	11.9	13.3	14.4	15.0	15.4	16.7	17.7
TRANSMISSION LINE REPL.	6.0	1.0	1.0	1.3	1.3	1.4	1.5	1.5	1.6	1.7
SUBSTATION REPLACEMENTS	2.4	1.0	1.4	1.2	1.6	1.3	1.4	1.5	1.5	1.6
SYSTEM PROTECTION REPLACEMENTS	6.6	5.3	3.2	4.2	3.8	3.8	3.9	3.8	4.2	4.5
POWER SYSTEM CONTROL REPLACEMENT	17.9	12.9	7.9	11.8	9.3	9.2	9.3	10.9	11.0	11.6
TOOLS AND EQUIPMENT	17.5	8.1	12.8	10.9	11.0	11.9	12.4	12.5	13.8	14.6
ENVIRONMENTAL RESTORATION	4.1	4.5	6.8	5.6	5.7	6.1	6.4	6.6	7.1	7.6
Subtotal General Plant	69.4	64.0	40.4	46.9	46.0	48.1	49.9	52.2	55.9	59.3
Total SR Program	159.7	102.2	89.1	92.3	102.1	94.3	99.0	104.7	109.9	115.9

V. POWER RATES HISTORY APPENDIX

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Structure of Power Rates History Appendix

The appendix presents historical rates information in several ways, as follows:

- Table A-1 shows current rate schedules and their predecessor schedules. The columns (a) through (q) contain current schedules (IP-93, PF-93, etc.) along the bottom row. Reading up each column you will find the rate schedules that served roughly the same purpose and same customer types as the current schedules shown in the bottom row. The year and effective date of each schedule are shown in the first two columns.
- When two schedules appear side by side under a single column label (e.g., column (c), schedules E-2 and F-2) those schedules both served a purpose similar to a single earlier or later schedule. A horizontal line appearing in a column signals discontinuance of schedules serving a given purpose.
- Table A-2 consists of 14 pages giving detailed information on every general rate schedule BPA has put into effect, beginning with BPA's first schedules in 1938. Each row represents a different rate schedule; rate schedule characteristics are denoted by dots in the appropriate column. Explanatory notes appear in the far right column. Footnotes are explained on page A-16; adjustments are described on page A-17.

Wholesale rate information for Publics and Cooperatives, Direct Service Industries, Nonfirm Energy Sales includes:

- Chronology of the rate schedules (and their energy and demand charges) predominantly or exclusively used by the group.
- Actual average rates: (a) by rate schedule; (b) annually, from sales under the predominant rate schedule; and (c) annually, from all sales to that group.

Revenue and sales data taken from BPA's Generation and Sales Statistics reports 1939-1992, except where otherwise noted. During 1938, rate schedules A-1, B-1, C-1, D-1 and E-1 were in effect. However, 1938 is only reflected in tables A-2 and A-2 due to the lack of historical data available to verify sales or revenues under these rate schedules.

Table A-1
Summary Of BPA Rate Schedules

	Eff. Date	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1938	06/08/38	A-1	C-1		B-1 D-1													E-1
1939	09/18/39	A-2	C-2	F-1	H-1													┆
1940		┆	┆	┆	┆													
1941		┆	┆	┆	┆													
1942	01/01/42	A-3	C-3	F-2	H-2													
1943		┆	┆	┆	┆													
1944	04/44	┆	┆	E-2 F-2	┆													
1945		┆	┆	┆	┆													
1946	03/01/46	A-4	C-4	E-3 F-3	H-3													
1947		┆	┆	┆	┆													
1948	04/01/48	┆	┆	E-4 F-4	┆	R-1												
1949		┆	┆	┆	┆	┆												
thru		┆	┆	┆	┆	┆												
1965		┆	┆	┆	┆	┆												
1966	12/20/65		C-5	E-5 F-5	H-4 S-1	R-2												
1967			┆	┆	┆	┆												
thru			┆	┆	┆	┆												
1974			┆	┆	┆	┆												
1975	12/20/74		IF-1 MF-1	EC-6	H-5		F-6	J-1	EC-7									
1976			┆	┆	┆		┆	┆	┆									
thru			┆	┆	┆		┆	┆	┆									
1979			┆	┆	┆		┆	┆	┆									
1980	12/20/79		IF-2 MF-2	EC-8	H-6		F-7	J-2	EC-9	F-8								
1981	07/01/81		IP-1 MP-1	PF-1	NF-1		CF-1	FE-1	RP-1	CE-1	NR-1	SI-1						
1982	10/01/82		IP-2 MP-2	PF-2	NF-2		CF-2	FE-2	RP-2	CE-2	NR-2	SI-2	SP-1	SE-1	EB-1			
1983	11/01/83		IP-83	PF-83	NF-83		CF-83		RP-83	CE-83	NR-83	IH-83	SP-83	SE-83	EB-83			
1984			┆	┆	┆		┆		┆	┆	┆	┆	┆	┆	┆			
1985	07/01/85		IP-85	PF-85	NF-85		CF-85		RP-85	CE-85	NR-85	SI-85	SP-85	SE-85	EB-85	SS-85	VI-86	FD-85
1986	08/01/86				NF-85 (amended)		┆		┆	┆	┆	┆	┆	┆	┆	┆	┆	┆
1987	10/01/87		IP-87	PF-87	NF-87		CF-87		RP-87	CE-87	NR-87	SI-87	SP-87			SS-87	VI-87	┆
1988	12/01/88		┆	┆	┆		┆		┆	┆	┆	┆	┆			┆	┆	MSL-87
1989	10/01/89		IP-89	PF-89	NF-89		CF-89		RP-89	CE-89	NR-89	SI-89	SP-89			SS-89	┆	┆
1990	10/01/90		┆	┆	┆		┆		┆	┆	┆	┆	┆			┆	┆	┆
1991	10/01/91		IP-91	PF-91	NF-91		CF-91		RP-91	CE-91	NR-91	SI-91	SP-91			SS-91	┆	┆
1992	10/01/92		┆	┆	┆		┆		┆	┆	┆	┆	┆			┆	┆	┆
1993	10/01/93		IP-93	PF-93	NF-93				RP-93	CE-93	NR-93	SI-93	SP-93			SS-93	VI-93	PS-93

Column Legend

Col	Rate Schedule	Title	Col	Rate Schedule	Title
(a)	A	At-site Firm Power	(i)	F-8, CE	Emergency Capacity
(b)	C-1 to C-4	Transmission System Firm Power	(j)	NR	New Resource Firm Power
	C-5	Firm, Modified Firm & Interruptible Power	(k)	SI	Special Industrial Power
	IF, IP	Industrial Firm Power		IH	Industrial Hanna
	MF, MP	Firm & Modified Firm Power	(l)	SP	Surplus Firm Power
(c)	F-1 to F-5	Wholesale Firm Power, Optional Schedule	(m)	SE	Surplus Firm Energy
	E-2 to E-5; EC-6, EC-8	Wholesale Firm Power	(n)	EB	Energy Broker
	PF	Priority Firm Power	(o)	SS	Share-the-Savings
(d)	B, D, H, S, NF	Nonfirm Energy; (S) Wholesale Excess Energy	(p)	VI	Variable Industrial Power
(e)	R	Firm Power for Railroads	(q)	E-1	Temporary Power for Experimental Use
(f)	F-6, F-7, CF	Wholesale Firm Capacity		FD	Firm Displacement Power
(g)	J, FE	Wholesale Firm Energy		SL, MSL	Long-Term Surplus Firm Power
(h)	EC-7, EC-9, RP	Reserve Power		PS-93	Power Shortage Rate

2 of 2

Table A-2
BPA Rate Schedule History

Available To: Rates 1/												
Effective Date	Rate Schedule	Title	Adjustments 2/	Firm	3/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	4/ Indus-trials (DSIs)	Extra Regional	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes
06/08/38	A-1	At Site Prime Power		■		■	■	■ 6/		--	1.21	Rate: \$14.50/kw-year.
	B-1	At Site Secondary Power			■	■	■	■ 6/		--	.79	Rate: \$9.50/kw-year.
	C-1	Transmission System Prime Power		■		■	■			--	1.46	Rate: \$17.50/kw-year.
	D-1	Transmission System Secondary Power			■	■	■			--	.96	Rate: \$11.50/kw-year.
11/01/38 Supplement	E-1	Temporary Power for Experimental Use *		■			■			--	1.46	Firm: \$17.50/kw-year or \$.0479/kw-day. NF: \$11.50/kw-year or \$.0315/kw-day. Experimental; effective only 11/1/38 - 12/31/39 Designed to enable sale of BPA power before transmission lines completed. (Rate used only if sales to Northwestern Electric Co.)
					■		■		--	.96		
09/18/39	A-2	At Site Power		■		■	■	■ 6/		--	1.21	Rate: \$14.50/kw-year.
	C-2	(a) Transmission System Prime		■		■	■	■ 6/		--	1.46	(a) Rate: \$17.50/kw-year.
		(b) Developmental Rate 7/		■		■				5.0	--	
	F-1	(a) Prime Power Optional Schedule *		■		■	■	■ 6/		2.5	.75	Designed to be more advantageous to utilities w LFs ≤ 45% (e.g., municipals and cooperative;
		(b) Developmental Rate 7/		■		■				5.0	--	
	H-1	Dump Energy *				■	■	■	■ 6/		2.5	--
* Both at site and transmission system.												

See footnotes on page A-16

**Table A-2
BPA Rate Schedule History**

Effective Date	Rate Schedule	Title	Available To:							Rates ^{1/}		Notes
			^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	^{4/} Industrials (DSLs)	Ex. Regional	Energy (m/KWh)	Capacity (\$/kw-mo) ^{5/}	
01/01/42	A-3	At Site Prime Power		■		■	■	■		--	1.21	Rate: \$14.50/kw-year.
	C-3	(a) Transmission System Prime Power		■		■	■	■		--	1.46	(a) Rate: \$17.50/kw-year.
		(b) Developmental Rate ^{7/}		■		■				5.0	--	
	F-2	(a) Prime Power, Optional Schedule *		■		■	■	■		2.5 - 1.0	.75	(a+c) Energy: 360 kWh*kW/month @ 2.5 m/kWh; additional kWh @ 1.0 m/kWh.
		(b) Developmental Rate ^{7/}		■		■				5.0	--	
		(c) Irrigation and Drainage Pumping		■		■	■	■		2.5 - 1.0	.75	\$.75/kW-month to maximum of \$4.50/kW-year. Special irrigation/pumping rate available on <u>firm</u> basis from April through September; interruptible other months NTE 4 hours/day.
	H-2	Dump Energy			■	■	■	■		2.5	--	
04/01/44 <i>Supplement</i>	E-2	(a) Wholesale Power for Resale		■		■	■			2 - 1	.75	Energy: First 200 kWh/kw @ 2 m/kWh, additional at 1 m/kWh.
		(b) Developmental Rate		■		■				3.5	--	Developmental rate available for 3-4 years.
		(c) Irrigation and Drainage Pumping		■		■				3.5	.75	Capacity: To maximum of \$4.50/kW-year. Available April through September.
* Both at site and transmission system.												

			Available To:							Rates ^{1/}		
Effective Date	Rate Schedule	Title	^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	^{4/} Industrials (DSIs)	Extra Regional	Energy (m/kWh)	^{5/} Capacity (\$/kw-mo)	Notes
03/01/46	A-4	At Site Prime Power		■		■	■	■		--	1.21	Rate: \$14.50/kw-year.
	C-4	Transmission System Firm Power		■		■	■	■		--	1.46	Rate: \$17.50/kw-year.
	E-3	(a) Wholesale Power For Resale *		■		■	■			2-1	.75	(a+c) Energy: First 200 kWh*kW 2 m/kWh; additional at 1 m/kWh.
		(b) Developmental Rate		■		■				3.5	--	(b) Developmental rate available 3-4 years.
		(c) Irrigation		■		■				2-1	.75	(c) Capacity: To maximum \$4.50/kW-year. Firm basis, April through September.
F-3	Firm Power; -- Optional*		■			■	■		2.5 - 1.	.75	Energy: First 360 kWh @ 2.5 m/kWh, additional at 1 m/kWh. Irrigation to maximum \$4.50/kW-year.	
	H-2	Dump Energy			■	■	■	■		2.5	--	
04/01/48 Supplement	E-4	(a) Wholesale Power For Resale*		■		■	■			2.0 - 1.0	.75	(a) Energy: First 200 kWh*kW @ 2 m/kWh; additional at 1 m/kWh.
		(b) Developmental Rate		■		■			3.5	--	(b) Developmental rate available 5 years.	
		(c) Irrigation		■		■			3.5	.75	(c) Total charge for power to maximum \$6.00/kW-year, firm basis, May through September. Nonfirm deliveries for irrigation at 50% of demand charge.	
	F-4	Firm Power; -- Optional*		■		■	■		2.5 - 1.0	.75	Energy: 360 kWh*kW/month @ 2.5 m/kWh; additional kWh @ 1.0 m/kWh.	
	R-1	Firm Power For Railroads*		■					4.0	--	For use by railroads primarily for traction purposes.	
07/01/52	E-4	Amendment										
12/20/54	E-4	(Amendment)										Change only: Irrigation discount of .4 m/kWh, May 1 through September 30.
12/20/64	F-4	(Amendment)									--	Change: Firm capacity may be purchased on a contract demand basis annually at for 5/1 - 10/30. Minimum charge: (1) Year-- \$9/kW-year or \$.75/kW-month; (2) Season-- \$5/kW-season or \$1/kW-month.
* Both at site and transmission system.												

**Table A-2
BPA Rate Schedule History**

Effective Date	Rate Schedule	Title	Available To:							Rates ^{1/}		Notes
			^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	^{4/} Industrials (DSIs)	Extra Regional	Energy (m/kWh)	^{5/} Capacity (\$/kw-mo)	
12/20/65	A-4	(Eliminated) ^{8/}										
	C-5	(a) Firm Power (b) Modified Firm Power ^{2/} (c) Interruptible		■		■	■	■		--	1.55	(a) At site rate: \$1.284/kW-month.
				■		■	■	■		--	1.50	(b) At site rate: \$1.243/kW-month.
						■	■	■		--	1.45	(c) At site rate: \$1.20/kw-month
	E-5	(a) Wholesale Firm Power (b) Developmental Rate	ID	■		■	■			1.25	.95	
				■		■	■					(b) Developmental rate discount = 5% or 2%, depending on ratio of total annual energy requirements of utility during prior CY, to average of utility's depreciated investment in EPIS.
	F-5	Wholesale Power Optional*	ID	■		■	■	■		2.5 - 1.25	.75	Energy: First 360 kWh/kW @ 2.5, additional at 1.25. Firm Capacity provisions, same as F-4 amendment (12/20/64).
12/20/74	R-2	Power for Railroads		■						4.25	--	For use by Railroads.
	H-4	Dump Energy			■	■	■	■		2.5	--	
	S-1	Wholesale Excess Energy			■	■	■	■	■	2.0	--	
	EC-6	Firm Power	UI, ID, TC	■		■	■			1.9W 1.0S	1.05W .93S	Reduction of \$.10/kW-month for at site power. Irrigation and developmental discounts phased out, 1975-1979.
	EC-7	Reserve Power	UI, TC	■		■	■	■		10.0W 5.0S	1.65W 1.40S	For unanticipated load growth, or on contract demand basis, of where no contract in force.
	F-6	Firm Capacity	TC	■		■	■			--	1.00	On <u>contract year</u> basis.
	H-5	Nonfirm Energy	UI		■	■	■	■	■	--	1.30	On <u>contract season</u> basis, Jun-Oct.
	J-1	Firm Energy		■		■	■			3.5W 3.0S	--	
	IF-1	Industrial Firm Power	UI	■				■		4.0	--	
	MF-1	Firm Power and Modified Firm Power	UI	■				■		1.525	1.20	At site capacity rate: \$.90/kW-month.
										1.525	1.20	Firm Power of authorized increase in firm of modified firm, on contract demand basis: @ site capacity rate-- \$.90/kW-month.
										1.525	1.15	Modified Firm @ site capacity rate: \$.85/Kw-month.

Table A-2
BPA Rate Schedule History

Available To: Rates												
Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	2/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOU's	4/ Indus-Trials (DSIs)	Extra Regional	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes
12/20/79	EC-8	Firm Power	UI, AS	■		■	■			4.13W 3.76S	1.95W 1.19S	For unanticipated load growth, or where no contract is in place or no other rate schedule applies.
	EC-9	Reserve Power	UI	■		■	■	■		26.7 26.7	6.16W 3.76S	
	IF-2	Industrial Firm Power	UI, AS, AC	■				■		4.13W 3.76S	1.95W 1.19S	
	MF-2	Modified Firm Power	UI, AS	■				■		4.13W 3.76S	1.95W 1.19S	For modified firm power on contract basis; and for authorized increase power; and on intermittent basis.
	F-7	Firm Capacity		■		■	■			-- --	1.57 1.946	<u>Contract Year:</u> on contract for year. <u>Contract Season:</u> on contract Jun-Oct. Capacity rate increased by \$.265/kW-month for each hour that monthly demand exceeds six hours.
	F-8	Emergency Capacity				■	■		■	-- --	1.82 2.193	<u>Within region rate:</u> \$.42/kW-week. <u>Sales over intertie rate:</u> \$.506/kW-week.
	J-2	Firm Energy		■		■	■			6.1	--	Contract rate: 5.5 m/kWh. Also non-thermal displacement rate of 6.5 m/kWh, on-peak; 4.5 m/kWh, off-peak. Maximum 20.0 m/kWh.
	H-6	Nonfirm Energy			■	■	■		■	Varies	--	

**Table A-2
BPA Rate Schedule History**

Available To:											Rates ^{1/}		Notes
Effective Date	Rate Schedule	Title	^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOU's	^{4/} Indus-trials (DSIs)	Extra Regional	Energy (m/kWh)	^{5/} Capacity (\$/kw-mo)		
07/01/81	PF-1	Priority Firm Power	UI, AS, LDD	■		■	■10/			7.4W 6.9S	2.80W 1.44S	Winter/Energy=the greater of 7.4 m/kWh or 1.7 + (X/2465) of billing energy. Summer/Energy=the greater of 6.9 m/kWh or 1.6 + (X/2480) of billing energy, where X=actual month's exchange costs. Rates same as for IP-1, except no Value of Reserves Credit. <u>Contract Year:</u> (\$25.44/kW-year). <u>Contract Season:</u> Jun-Oct. (\$11.76/kW-seas) Capacity rate increased by \$.029/kW-month when monthly demand exceeds 9 hours. <u>Non-Intertie Rate:</u> \$.56/kW-week. <u>Sales over Intertie Rate:</u> \$.78/kW-week. To serve any increase in consumption as defined by PNW Power Act Contract rate: 9.6 m/kWh. Floor rates: 6.5 m/kWh, peak; and 5.0 m/kWh, off-peak. For unanticipated load growth, or other By contract. Hanna Nickel Smelting Co. only. Energy Rate: Winter = greater of 7.4 m/kWh or (X/2465-.4.8) m/kWh; Summer = greater of 6.9 m/kWh or (X/2480-.4.9) m/kWh, where X= BPA's actual monthly exchange costs. Maximum energy rate of 10.6 m/kWh.	
	IP-1	Industrial Firm Power	UI, AS, VOR	■				■		SEE NOTE	2.80W 1.44S		
	MP-1	Modified Firm Power	UI, AS	■				■					
	CF-7	Firm Capacity		■			■			-- --	2.12 2.352		
	CE-1	Emergency Capacity					■		■	-- --	2.427 3.38		
	NR-1	New Resource Firm Power		■			■	■		30.8W 24.7S	2.80W 1.44S		
	NF-1	Nonfirm Energy				■	■	■	■	Varies	--		
	RP-1	Reserve Power	UI	■	■		■	■	■	62.1 62.1 10.0	12.57W 3.47S --		
	FE-1	Firm Energy		■	■		■	■					
	SI-1	Special Industrial Power	UI, VOR	■	■				■	SEE NOTE	2.80W 1.44S		

Table A-2
BPA Rate Schedule History

Effective Date	Rate Schedule	Title	Available To:			Rates ^{1/}		Extra Regional	Energy (m/kWh)	Capacity (\$/kw-mo)	Notes
			^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	^{4/} Industrials (DSIs)			
10/01/82	PF-2	Priority Firm Power	UI, EA, LDD	■		■	■ 10/		12.4W 11.8S	4.21W 1.91S	Standard: FQ service w/NF & borrowing techniques. Premium: FQ service w/surplus FELCC. Hanna only.
	IP-2 (MP-2)	Industrial Firm Power	UI, EA, VOR	■				■	24.8W 22.8S	4.21W 1.91S	
				■				■	27.8W 25.6S	4.21W 1.91S	
	SI-2	Special Industrial Power (Hanna)	UI, VOR	■				■	12.4W 11.8S	4.21W 1.91S	
	CF-2	Firm Capacity	EA	■					--	3.06	Contract Year: capacity rate increased by \$.024/kW-month when monthly demand duration exceeds 9 hours. Contract Season: Jun-Oct.; capacity rate increased by \$.024/kW-month when monthly demand duration exceeds 9 hours. Non-Intertie Rate: \$.81/kW-week. Sales over Intertie Rate: \$1.00/kW-week.
									--	2.66	
	CE-2	Emergency Capacity							--	3.51 4.33	
	FE-2	Firm Energy		■					16.4	--	
	NR-2	New Resource Firm Power	UI, EA	■		■	■		26.7W 24.5S	4.21W 1.91S	Alternative energy charge formula for rate based on discretionary resource acquisitions.
	SP-1	Surplus Firm Power	UI, EA	■		■	■		28.4	4.21W 1.91S	
	SE-1	Surplus Firm Energy	EA	■		■	■		28.4		
	NF-2	Nonfirm Energy			■	■	■	■	9.0 11.2 18.2 >18.2	--	
	EB-1	Energy Broker			■		■				(a) Spill rate. (b) Contract rate. (c) Standard rate. (d) Incremental cost, if > 16.2 m/kWh, plus 2.0 m/kWh. STS formula used for participation in WSCC Energy Broker System. ^{1/}
	RP-2	Reserve Power	UI	■		■	■	■	42.3	8.35W 4.17S	For unanticipated load growth, or other

**Table A-2
BPA Rate Schedule History**

Effective Date	Rate Schedule	Title	Available To:					Rates ^{1/}			Notes	
			^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOU's	^{4/} Indus-trials (DSIs)	Extra Regional	Energy (m/kWh)		^{5/} Capacity (\$/kw-mo)
11/01/83	PF-83	Priority Firm Power	UI, EA, LDD, SAA	■		■	■ ^{10/}			15.9W 12.7S	5.57W 2.42S	
	IP-83	Industrial Firm Power	UI, EA, VOR	■				■		14.7W 12.2S	4.62W 2.42S	<u>Standard:</u> Includes customer charge of \$7.34/kW.
				■				■		15.9W 12.7S	5.57W 2.42S	<u>Premium:</u> Includes customer charge of \$9.63/kW.
	IH-83	Industrial Hanna	UI, VOR	■				■		15.9W 12.7S	5.57W 2.42S	Industrial incentive rate specified in contract. (a) <u>Standard</u> = same as IP-83 Premium.
										7.0	--	(b) <u>Off-peak</u> = energy only (no VOR credit).
	CF-83	Firm Capacity	EA, SSA	■						--	3.73	<u>Contract Year</u>
										--	2.42	<u>Contract Season:</u> Jun-Oct.;
										--	5.57W	<u>General Service:</u> Winter = Dec. - Apr.
										--	2.42S	<u>General Service:</u> Summer = May- Nov.
	CE-83	Emergency Capacity	UI, EA							--	4.85	On contract demand basis. Increase rates by \$.12/kW-month for intertie service. Increase rates by \$.048/kW-month for extended peaking surcharge (when demand duration > 9 hours).
	NR-83	New Resource Firm		■		■	■			26.3W 21.0S	5.57W 2.42S	Rate billed at \$1.12/kW-week. Intertie charge of \$.03/kW-week.
	SP-83	Surplus Firm Power		■		■	■		■	25.9	3.85	Contract rate. Short-term sales ending by 6/30/85 could be based on cost of specific resources. Specific escalation factors for long-term sales.
	SE-83	Surplus Firm Energy		■		■	■		■	31.1	--	Subject to same escalation factors as SP rate.
	NF-83	Nonfirm Energy			■	■	■	■	■	18.5 11.0 13.9	-- -- --	<u>Standard.</u>
											<u>Spill.</u>	
											<u>Contract.</u>	
EB-83	Energy Broker	UI		■				■			Also displacement rate (3 or 7 m/kWh) and incremental rate (> 18.5 m/kWh).	
RP-83	Reserve Power		■		■	■	■		34.3	7.51W 2.01S	STS formula used for participation in WSCC Energy Broker System. 11/	

Table A-2
BPA Rate Schedule History

Available To: Rates													
Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	2/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	4/ Indus- trials (DSIs)	Extra Regional	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes	
07/01/85	PF-85	Priority Firm Power	UI, EA, LDD, SAA, CS, OC, ID, ERS	■		■	■ 10/			16.6W 14.0S	4.33W 2.60S		
	IP-85	Industrial Firm Power	UI, OC, VOR	■				■		19.0W 15.2S	7.13W 3.96S	(a) <u>Standard</u> : TQ service w/NF & borrowing techniques.	
				■			■		19.4W 15.5S	7.28W 4.05S	(b) <u>Premium</u> : TQ service w/surplus FELCC. (c) Also incentive rate per contract. (no VOR credit)		
	SI-85	Special Industrial	UI, OC, VOR	■				■ 12/	16.6W 4.0S 7.0	4.33W 2.60S	(a) <u>Standard</u> (b) <u>Off-peak</u> Energy only (no VOR credit)		
	CF-85	Firm Capacity	EA, SAA, CS, ERS, EPS	■						-- --	3.62 2.53	<u>Contract Year</u> <u>Contract Season</u> : Jun-Oct.;	
	CE-85	Emergency Capacity								--	4.72	Rate billed at \$1.09/kW-week Intertie charge of additional \$.11/kW-week.	
	NR-85	New Resource Firm	UI, EA, CS, ERS, OC, ID	■		■	■			22.0W 18.0S	7.81W 4.31S		
	SP-85	Surplus Firm Power	ERS, EPS	■		■	■		■	20.6	5.90	Contract rate. Also, resource rate. Intertie service charge = 1.2 m/kWh or \$.87/kW-month..	
	SE-85	Surplus Firm Energy		■		■	■		■	28.7	--	Rate may be otherwise specified in contract. Intertie use charge = 1.2 m/kWh. Specified escalation factors for sales extending beyond 9/30/87.	
	NF-85	Nonfirm Energy	GDS		■	■	■		■	18.1 22.2 12.8	-- -- --	<u>Contract</u> <u>Standard</u> <u>High cost displacement</u> . Also low cost displacement rate and incremental rate. Intertie use charge = 1.2 m/kWh. Formula rate for certain uses and users.	
	SS-85	Share-the-Savings			■	■	■		■				STS formula used for participation in WSCC Energy Broker System. 11/
EB-85	Energy Broker			■		■	■		■				
RP-85	Reserve Power			■		■	■		■	24.7	6.56W 2.60S		

**Table A-2
BPA Rate Schedule History**

Available To: Rates 1/												
Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	3/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	4/ Indus- trials (DSIs)	Extra Regionals	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes
08/01/86 Supplement	VI-86	Variable Industrial Power	UI, OC	■				■ 13/		16.0	5.28	Base Rate: First Quartile discount = .5 m/kWh; lower limit = 8.2 m/kWh; upper limit = 21.8 m/kWh. Rate tied to price of aluminum. These are initial rate charges. Rate parameters subject to change when BPA has a rate case. Monthly rate varies with the price of aluminum. Contract Rate: For contracts with 12 months/year service Capacity charge adder for contracts with less than 12 months/year. Load factor credit. Amends high cost displacement rate to be offered rate from 7 to 22.2 m/kWh.
	FD-85	Firm Displacement Power	ERS, EPS	■		■ 14/	■ 14/			22.2	5.69	
	NF-85	Amendment	GDS									

Table A-2
BPA Rate Schedule History

Available To: Rates ☒												
Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	2/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOU's	4/ Indus- trials (DSIs)	Extra Regional	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes
10/01/87	PF-87	Priority Firm Power	UI, LDD, CS, OC, ID, ERS, CRAC, CBA	■		■	■ 10/			18.4W 14.4S 19.1W 15.1S	3.46 3.56	<u>Preference Rate.</u> <u>Exchange Rate</u>
	IP-87	Industrial Firm Power	UI, OC, CRAC	■				■		19.5W 15.6S	4.14	Discount for quality of First Quartile Service = .6 m/kWh.
	VI-87	Variable Industrial Power	UI, OC, CRAC	■				■ 13/		16.1	5.33	<u>Base Rate.</u> 1st Quartile discount = .5 m/kWh; lower limit = 8.3 m/kWh; upper limit = 21.9 m/kWh. Rate tied to price of aluminum. Rate parameters change when BPA has a rate case
	NF-87	Nonfirm Energy	GDS		■	■	■		■	≤21.6 14.9	-- --	<u>Standard.</u> <u>Contract.</u> Intertie charge = 1.4 m/kWh; also, market expansion rate and incremental rate. Avg. cost of NF = 18.0 m/kWh.
	CF-87	Firm Capacity	CRAC, CS, ERS, EPS	■						--	3.54	<u>15/</u>
	CE-87	Emergency Capacity								--	4.59	Rate @ 1.06/kW-week. Intertie charge of \$.15/kW-week.
	NR-87	New Resource Firm Power	CRAC, ID, CS, UI, CBA, OC, ERS	■		■	■			25.5W 21.2S	4.13	
	SI-87	Special Industrial Power	UI, OC	■				■ 12/		16.9W 12.9S 7.0	3.08 --	(a) <u>Standard</u> (b) <u>Off-peak</u>
	SP-87	Short-Term Surplus Firm Power		■		■	■		■	24.3	4.29	Contract rate. Also, flexible rate. Intertie charge = .36/kW-month and .69 m/kWh.
	SS-87	Share-the-Savings			■	■	■		■			Formula rate based on decremental cost; under contract only.
	RP-85	Reserve Power		■		■	■	■	■	25.3	3.64	
12/01/88	MSL-87	Modified Long-Term Surplus Firm Power		■		■	■					Rate subject to floor and ceiling; negotiated.

Table A-2
BPA Rate Schedule History

Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	3/ Non-Firm	Available To:				Rates 1/		Notes
						PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	4/ Indus-trials (DSIs)	Extra Region AL	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	
10/01/89	PF-89	Priority Firm Power	UI, LDD, CS, OC, ID, ERS, CRAC, CBA	■		■	■ 10/			18.4W 14.4S 19.1W 15.1S	3.46 3.56	<u>Preference Rate.</u> <u>Exchange Rate</u>
	IP-89	Industrial Firm Power	UI, OC, CRAC	■				■		19.5W 15.6S	4.14	Discount for quality of First Quartile Service = .6 m/kWh.
	VI-87	Variable Industrial Power	UI, OC, CRAC	■				■ 13/		16.1	5.33	<u>Base Rate.</u> 1st Quartile discount = .5 m/kWh; lower limit = 8.3 m/kWh; upper limit = 21.9 m/kWh. Rate tied to price of aluminum. Rate parameters change when BPA has a rate case.
	NF-89	Nonfirm Energy	GDS		■	■	■		■	≤21.6 14.9	-- --	<u>Standard.</u> <u>Contract.</u> Intertie charge = 1.4 m/kWh; also, market expansion rate and incremental rate. Avg. cost of NF = 18.0 m/kWh.
	CF-89	Firm Capacity	CRAC, CS, ERS, EPS	■						--	3.54	<u>15/</u>
	CE-89	Emergency Capacity								--	4.59	Rate @ 1.06/kW-week. Intertie charge of \$.15/kW-week.
	NR-89	New Resource Firm Power	CRAC, ID, CS, UI, CBA, OC, ERS	■		■	■			25.5W 21.2S	4.13	
	SI-89	Special Industrial Power	UI, OC	■				■ 12/		16.9W 12.9S 7.0	3.08 --	(a) <u>Standard</u> (b) <u>Off-peak</u>
	SP-89	Short-Term Surplus Firm Power		■		■	■		■	24.3	4.29	Contract rate. Also, flexible rate. Intertie charge = .36/kW-month and .69 m/kWh.
	SS-89	Share-the-Savings			■	■	■		■			Formula rate based on decremental cost; under contract only.
	RP-89	Reserve Power		■		■	■	■	■	25.3	3.64	

**Table A-2
BPA Rate Schedule History**

Available To:											Rates	1/	
Effective Date	Rate Schedule	Title	2/ Adjustments	Firm	3/ Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOU's	4/ Indus-trials (DSLs)	Extra Region AL	Energy (m/kWh)	5/ Capacity (\$/kw-mo)	Notes	
10/01/91	PF-91	Priority Firm Power	UI, LDD, CS, OC, ID, ERS, CBA	■		■	■ 10/			18.7W 14.7S 19.1W 15.1S	3.60 3.66	<u>Preference Rate.</u> <u>Exchange Rate:</u>	
	IP-91	Industrial Firm Power	UI, OC,	■				■		18.9W 15.2S	4.38	Discount for quality of First Quartile Service = .7 m/kWh.	
	VI-87	Variable Industrial Power	UI, OC	■				■ 13/		15.9	5.26	<u>Base Rate.</u> 1st Quartile discount = .5 m/kWh; lower limit = 10.1 m/kWh; upper limit = 21.7 m/kWh. Rate tied to price of aluminum. Rate parameters change when BPA has a rate case.	
	NF-91	Nonfirm Energy	GDS		■	■	■		■	≤ 22.9 18.1	-- --	<u>Standard Contract.</u> Intertie charge = 2.1 m/kWh; also, market expansion rate and incremental rate. Avg. cost of NF = 19.1 m/kWh.	
	CF-91	Firm Capacity	CS, ERS, EPS	■						--	3.65	15/	
	CE-91	Emergency Capacity								--	4.72	Rate @ 1.09/kW-week. Intertie charge of \$.20/kW-week.	
	NR-91	New Resource Firm Power	ID, CS, UI, CBA, OC, ERS	■		■	■			25.9W 21.4S	4.40		
	SI-91	Special Industrial Power	UI, OC	■				■ 12/		17.0W 13.0S	3.16	(a) <u>Standard</u>	
	SP-91	Short-Term Surplus Firm Power			■		■	■		■	24.3	4.58	<u>Contract rate.</u> Also, flexible rate. Intertie charge = .36/kW-month and .69 m/kWh.
	SS-91	Share-the-Savings				■	■	■		■			Formula rate based on decremental cost; under contract only.
	RP-91	Reserve Power			■		■	■		■	25.3	3.64	

**Table A-2
BPA Rate Schedule History**

Effective Date	Rate Schedule	Title	AVAILABLE TO:							RATES ^{1/}		Notes
			^{2/} Adjustments	Firm	^{3/} Non-Firm	PNW Public Bodies, Co-Ops, Federal Agencies	PNW IOUs	^{4/} Industrials (DSIs)	Extra Region AL	Energy (m/kWh)	^{5/} Capacity (\$/kw-mo)	
10/01/93	PF-93	Priority Firm Power	UI, LDD, CS, OC, ID, ERS, CBA, IRA, ETA	■		■	■ ^{10/}			22.17W 16.29S 22.17W 16.29S	4.141 4.141	<u>Preference Rate.</u> <u>Exchange Rate</u>
	IP-93	Industrial Firm Power	UI, OC, IRA, ETA	■				■		21.06W 17.33S	5.112	Discount for quality of Firm: Quartile Service = .69 m/kWh.
	VI-91	Variable Industrial Power	UI, OC, IRA, ETA	■				■ ^{13/}		18.11	5.993	<u>Base Rate.</u> 1st Quartile discount = .57 m/kWh; lower limit = 13.31 m/kWh; upper limit = 23.91 m/kWh. Rate tied to price of aluminum. Rate parameters change when BPA has a rate case.
	NF-93	Nonfirm Energy	GDS, IRA, ETA		■	■	■		■	≤ 26.89 14.26	-- --	<u>Standard Contract.</u> Intertie charge = 3.11 m/kWh; also, market expansion rate and incremental rate. Avg. cost of NF = 22.41 m/kWh.
	PS-93	Power Shortage	ETA	■		■	■			Flexible	Flexible	≥ 100 m/kWh
	CE-93	Emergency Capacity								--	Flexible	Rate up to \$0.309/kW-day. Intertie charge of \$.042/kW-day.
	NR-93	New Resource Firm Power	ID, CS, UI, CBA, OC, ERS, IRA, ETA	■		■	■			27.56W 24.13S	5.151	
	SI-93	Special Industrial Power	UI, OC, IRA, ETA	■				■ ^{12/}		20.38W 14.50S	3.680	(a) <u>Standard</u>
	SP-93	Short-Term Surplus Firm Power	IRA, ETA	■		■	■		■	26.30	5.151	<u>Contract rate.</u> Also, flexible rate. Intertie charge = .706/kW-month and 1.69 m/kWh.
	SS-93	Share-the-Savings			■	■	■		■			Formula rate based on decremental cost; under contract only.
	RP-93	Reserve Power		■		■	■		■	25.30	3.640	

Explanation of Table A-2 Footnotes

1/ Beginning December 20, 1974, rates were seasonally differentiated as follows:

Effective Date	/----- Demand -----/ (Winter) (Summer)		/----- Energy -----/ (Winter) (Summer)	
12/20/74	Sep-Mar	Apr-Aug	Sept-Mar	Apr-Aug
12/20/79	Dec-May	Jun-Nov	Sept-Mar	Apr-Aug
11/01/83	Dec-Apr	May-Nov	Sept-Mar	Apr-Aug
10/01/87	(Flat Annual)		Sept-Mar	Apr-Aug
10/01/89	(Flat Annual)		Sept-Mar	Apr-Aug
10/01/91	(Flat Annual)		Sept-Mar	Apr-Aug
10/01/93	(Flat Annual)		Sept-Mar	Apr-Aug

2/ See page A-17 for list of abbreviations and adjustments.

3/ While firm energy and/or capacity is guaranteed to be available to purchase at all times, nonfirm energy may be interrupted.

4/ Rate schedules through 1945 include sales to "private persons," referring to industrial customers.

5/ No demand charge for off-peak hours (10 p.m. - 7 a.m., Monday-Saturday; all day Sunday), beginning December 20, 1979.

6/ Not for resale.

7/ Rates C-2, C-3, F-1, F-2 allow new full-requirements publics and cooperatives a 2-year developmental rate of 5.0 m/kWh, no demand charge.

8/ Specific "at-site" rate schedule combined with transmission system schedule December 20, 1965. At site discounts was available in these rate schedules until 1982.

9/ Modified Firm Power: subject to restriction NTE 25 percent of contract demand and NTE 500 kWh * contract demand in a year.

10/ Under Residential Exchange and WNP-1 Exchange only.

11/ Participants of western Systems Coordination Council (WSCC) Energy Broker System.

12/ DSI uses raw materials indigenous to the PNW.

13/ Aluminum smelters only.

14/ Contract purchases of power of capacity for use within the PNW, to replace utility's exported resources.

15/ CF rate not available for new contracts.

Explanation of Table A-2 Abbreviations and Adjustments

AC:	Availability Credit		
AS:	At-site Power; Demand charge reduced by \$.257/kW-mo		
CBA:	Coincidental Billing Adjustment		
CRAC:	Cost Recovery Adjustment Clause		
CS:	Conservation Surcharge		
EA:	Exchange Adjustment		
EPS:	Extended Peaking Surcharge		
ERS:	Energy Return Surcharge		
ETA:	Energy Tax Adjustment		
GDS:	Guaranteed Delivery Surcharge		
ID:	Irrigation Discount:		
	1965 Rates:	.6 m/kWh, with 10 percent increase in energy for losses. All months.	
	1974 Rates:	Irrigation Discount phased out; 1974 - 1979.	
	1985 Rates:	3.7 m/kWh; April through August. Losses not included.	
	1987 - 1991	4.6 m/kWh; April through August. Losses not included.	
	1993 Rates:	4.71 m/kWh; April through August. Losses not included.	
IRA:	Interim Rate Adjustment		
LDD:	Low Density Discount; 3 percent, 5 percent, or 7 percent discount off purchased power cost for Qualifying utilities.		
OC:	Outage Credit		
SSA:	Supply System Adjustment		
TC:	Transformation Charge; \$.12/kW for 115 kV and \$.20/kW for less than 100 kV.		
UI:	Unauthorized Increase charge:		
	1974 & 1979:	\$.10/kWh	
	1981:	\$.13/kWh	
	1982 & 1983:	83.0 m/kWh	
	1985:	82.2 m/kWh	
	1987 & 1989:	67.3 m/kWh	
	& 1991		
	1993	100.00 m/kWh August - March; 57.40 m/kWh April - July	
VOR:	Value of Reserves credit:		
	Schedule	\$/kW-month	mills/kWh
	1981 IP-1, SI-1	.33	2.3
	1982 IP-2, SI-2	1.31	.4
	1983 IP-83, IH-83	.23	1.6
	1985 IP-85, SI-85	.36	1.4
	(Credit not separately identified after 1985)		

Table A-3
Principal BPA Rate Schedules
To Public Agencies and Cooperatives

/-----Rates 1/-----/						
	Rate 2/ Schedule	Demand	Demand	Energy	Energy	Notes 3/
		(\$/kW-mo)		(mills/kWh)		
1939	F-1	.75		2.50		DR
1940						
1941						
1942	F-2	.75		2.50		DR
1943						
1944	E-2	.75		2.00	1.00 4/	DR, ID
1945						
1946	E-3	.75		2.00	1.00 4/	DR, ID
1947						
1948	E-4	.75		2.00	1.00 4/	DR, ID
thru						
1965						
1966	E-5	.95		1.25		DR, ID
thru						
1974						
1975	EC-6	1.05 W	.93 S	1.90 W	1.00 S	DR, ID, UI, AS
thru						TOU rates initiated 5/
1979						
1980	EC-8	1.95 W	1.19 S	4.13 W	3.75 S	UI, AS
1981	PF-1	2.80 W	1.44 S	7.40 W	6.90 S	UI, AS, LDD
1982	PF-2	4.21 W	1.91 S	12.40 W	11.80 S	UI, LDD, EA
1983	PF-83	5.57 W	2.42 S	15.90 W	12.70 S	UI, LDD, EA, SAA
1984						
1985	PF-85	4.33 W	2.60 S	16.60 W	14.00 S	ID, UI, LDD, EA,
1986						SSA, CS, OC, ERS
1987	PF-87 Pref. 6/	3.46		18.40 W	14.40 S	ID, UI, LDD, CS,
1988						OC, ERS, CRAC, CBA
1989	PF-89 Pref. 6/	3.46		18.40 W	14.40 S	ID, UI, LDD, CS,
1990						OC, ERS, CRAC, CBA
1991	PF-91 Pref. 6/	3.60		18.70 W	14.70 S	ID, UI, LDD, CS,
1992						OC, ERS, CBA
1993	PF-91 Pref. 6/	4.141		22.19 W	16.29 S	ID, UI, LDD, CS, OC,
						ERS, CBA, IRA, ETA

1/ Beginning in 1975, rates were seasonally differentiated. See bottom of page A-19.

2/ Through 1974, rate schedules C-2 through C-5 were used by several larger municipals and PUDs. During some years, as much as half of the energy sold to publics was sold under the rate schedules. See Table A-7, DSIs. After 1974, all publics and cooperatives were using the EC/PF rate schedules.

3/ See page A-17 for explanation of abbreviations.

4/ The E-2, E-3, and E-4 energy charge: the first 200 kWh per kW at 2.0 mills/kWh, additional kWh at 1.0 mill/kWh.

5/ TOU = Time-of-use rates: no capacity charge during off-peak hours. (10 p.m. - 7 a.m., MON-SAT; all day SUN.)

6/ The Preference rate is available for the general requirements for public body, cooperative and federal agency customers. The Exchange rate is available for all purchases of residential and small farm purchases.

Table A-4
Average Rate by Rate Schedule
Priority Firm Power and Predecessor Rates 1/

Effective Date	Rate Schedule	Actual Average Rate <u>2/</u> (mills/kWh)
09/18/39	F-1, F-2	3.8
04/01/44	E-2	3.3
03/01/46	E-3	3.2
04/01/48	E-4	3.1
12/20/65	E-5	3.1
12/20/74	EC-6	3.7
12/20/79	EC-8	7.4
07/01/81	PF-1	11.0
10/01/82	PF-2	18.0
11/01/83	PF-83	22.7
07/01/85	PF-85	21.4
10/01/87	PF-87	22.6
10/01/89	PF-89	22.6
10/01/91	PF-91	25.3 <u>3/</u>

- 1/ These rate schedules have been used by the majority of public agencies and cooperatives to purchase BPA power. However, until 1975, several larger municipals and PUDs purchased BPA power under the C Rate schedules, while the smaller public agencies and all the cooperatives used the schedules in this table. After 1974, all publics and cooperatives were using the EC and PF rate schedule.
- 2/ Average rates are calculated by dividing revenues by MWhs sold under each rate schedule, including discounts and adjustments. Note that EC-8, PF-1, PF-83, and PF-85 rate periods were short and included more of one season than the other; average rates may be skewed due to seasonality of rates.
- 3/ Reflects PF-91 sales through December 1992 only.

Table A-5
Average Annual Rates
Priority Firm Power and Predecessor Rates 1/

Calendar Year	Avg. Rate <u>2/</u> (mills/kWh)	Calendar Year	Avg. Rate <u>2/</u> (mills/kWh)
1939	4.8	1966	3.1
1940	5.2	1967	3.1
1941	5.5	1968	3.1
1942	3.8	1969	3.2
1943	3.7	1970	3.1
1944	3.6	1971	3.1
1945	3.3	1972	3.2
1946	3.3	1973	3.1
1947	3.3	1974	3.2
1948	3.2	1975	3.7 <u>3/</u>
1949	3.2	1976	3.7
1950	3.2	1977	3.7
1951	3.2	1978	3.7
1952	3.2	1979	3.8
1953	3.2	1980	7.3
1954	3.2	1981	8.9
1955	3.1	1982	13.1
1956	3.1	1983	19.4
1957	3.2	1984	22.2
1958	3.1	1985	21.9
1959	3.1	1986	22.0
1960	3.1	1987	21.7
1961	3.1	1988	22.5
1962	3.1	1989	22.6
1963	3.1	1990	22.6
1964	3.0	1991	22.7
1965	3.1		

-
- 1/ These average rates are derived from sales made under the one rate schedule used by the majority of public agencies and cooperatives each year. These include the F-1, F-2, E-2 through E-5, EC-6, EC-8, and PF rate schedules. Note, however, that until 1975, several larger municipals and PUDs purchased BPA power under the C rate schedules, while the small public agencies and all the cooperatives used the schedules in this table. After 1974, all publics and cooperatives were using the EC and PF rate schedules.
- 2/ Average rates are calculated by dividing revenues by MWhs sold under each rate schedule, including discounts and adjustments.
- 3/ 1975 and after, includes sales to IOUs.

Table A-6
Annual BPA Wholesale Firm Power Sales
to Public Agencies & Cooperatives 1/

Calendar Year	MWhs <u>2/</u>	Revenues (\$)	Avg. Rate	Calendar Year	MWhs <u>2/</u>	Revenues (\$)	Avg. Rate
1939	729	2,528	3.5	1966	17,366,199	47,811,171	2.8
1940	11,432	43,095	3.8	1967	17,789,870	50,198,473	2.8
1941	63,217	217,255	3.4	1968	17,419,481	50,005,962	2.9
1942	125,174	391,052	3.1	1969	18,999,456	57,077,135	3.0
1943	204,979	703,895	3.4	1970	20,460,414	58,686,878	2.9
1944	249,835	748,780	3.0	1971	22,049,208	64,358,165	2.9
1945	746,589	1,954,926	2.6	1972	24,181,267	70,832,966	2.9
1946	477,144	1,356,814	2.8	1973	25,834,366	73,949,738	2.9
1947	930,052	2,694,680	2.9	1974	27,064,092	78,893,782	2.9
1948	1,753,957	4,814,549	2.7	1975	29,090,860	109,292,931	3.8 <u>3/</u>
1949	2,367,378	6,829,240	2.9	1976	30,744,326	115,554,186	3.8
1950	2,938,167	8,891,193	3.0	1977	34,103,217	127,507,663	3.7
1951	3,838,082	10,844,793	2.8	1978	34,421,921	129,130,884	3.8
1952	4,793,595	12,935,968	2.7	1979	38,167,115	145,979,965	3.8
1953	4,808,144	13,379,168	2.8	1980	37,628,447	266,967,387	7.1
1954	5,267,078	15,510,968	2.9	1981	37,522,696	333,665,442	8.9
1955	6,631,474	18,356,417	2.8	1982	36,080,774	473,720,219	13.1
1956	7,120,900	20,219,034	2.8	1983	30,930,271	600,135,201	19.4
1957	8,278,481	22,397,793	2.7	1984	34,154,640	761,134,308	22.3
1958	8,576,046	23,081,869	2.7	1985	38,229,946	835,080,050	21.8
1959	9,666,744	26,595,080	2.8	1986	33,519,330	738,536,676	22.0
1960	10,844,586	29,196,921	2.7	1987	35,688,341	774,933,128	21.7
1961	11,274,083	30,526,197	2.7	1988	37,838,729	851,657,309	22.5
1962	12,529,987	33,803,119	2.7	1989	39,844,632	900,170,091	22.6
1963	13,196,689	36,697,477	2.8	1990	41,322,116	934,854,097	22.6
1964	14,376,538	38,295,350	2.7	1991	41,607,913	946,087,828	22.7
1965	15,995,386	43,598,271	2.7	1992	42,519,907	970,958,641	22.8

-
- 1/ Includes all sales under all firm power rate schedules used by BPA's northwest public agency and cooperative customers.
- 2/ Includes nonfirm sales (1940-42 and 1945).
- 3/ 1975 and after, slight differences in average rates between Table A-5 and Table A-6 may exist because sales in Table A-5 may include purchases by IOUs. Table A-6 may also include small amounts of sales under other rate schedules not included in Table A-5.

Table A-7
Principal BPA Rate Schedules
To Direct Service Industries (DSIs) 1/

	Rate 3/ Schedule	Demand	Demand	Energy	Energy	Notes 4/
		(\$/kW-mo)		(mills/kWh)		
1939	C-2	1.46				DR
1940						
1941						
1942	C-3	1.46				DR
1943						
1944						
1945						
1946	C-4	1.46				
thru						
1965						
1966	C-5	1.55	1.50 5/			AS
thru						
1974						
1975	IF-1	1.20		1.525		AS, UI
thru						TOU rates
1979						initiated 6/
1980	IF-2	1.95 W	1.19 S	4.13 W	6.76 S	AC, AS, UI
1981	IP-1	2.80 W	1.44 S	7.40 W	6.90 S	AS, UI, VOR 7/
1982	IP-2	4.21 W	1.91 S	24.80 W	22.80 S	EA, UI, VOR,
1983	IP-83	4.62 W	2.42 S	14.70 W	12.20 S	EA, UI, VOR,
1984						
1985	IP-85	7.13 W	3.96 S	19.00 W	15.20 S	ID, OC, VOR
1986						
1987	IP-87	4.14		19.50 W	15.60 S	CRAC, OC, UI
1988						
1989	IP-89	4.14		19.50 W	15.60 S	CRAC, OC, UI
1990						
1991	IP-91	4.38		18.90 W	15.20 S	OC, UI
1992						

- 1/ See Table A-8 for Aluminum Smelter DSIs.
- 2/ Beginning in 1980, DSI rates were seasonally differentiated. See bottom of page A18.
- 3/ Rate schedules C-2 through C-5 were also used by IOUs and by larger municipals and PUDs.
- 4/ See page A-17 for explanation of abbreviations.
- 5/ C-5: Firm = \$1.55; Modified Firm = \$1.50; also interruptible rate of \$1.45/kW-mo.
- 6/ TOU = Time-of-use rates: no capacity charge during off-peak hours.
(10 p.m. - 7 a.m., MON-SAT; all day SUN.)
- 7/
IP-1 energy	<u>Winter</u>	=	The greater of 7.4 mills/kWh.
		<u>or</u>	1.7+(X/2465) of billing energy.
	<u>Summer</u>	=	The greater of 6.9 mills/kWh
		<u>or</u>	1.6+(X/2480) of billing energy.
	Where X	=	Actual month's costs incurred by BPA.

Table A-8 **BPA Rate Schedules to Aluminum Smelters** **Variable Industrial (VI) Rate**

Calendar Year 1/	Rate Schedule	Rates -----/						Notes 3/
		Demand	Plateau	Rate Limit		Pivot Point		
			Energy	Lower	Upper	Lower	Upper	
			(mills/kWh) 2/	(mills/kWh)	(mills/kWh)	(¢/lb)	(¢/lb)	
1986	VI-86	5.28	16.0	8.2	21.8	61.0	72.0	UI, OC
1987	VI-87	5.33	16.1	8.3	21.9	60.8	73.4	UI, OC, CRAC
1988		5.33	16.1	9.3	21.9	67.0	75.2	
1989		5.33	16.1	9.3	21.9	74.8	77.4	
1990		5.33	16.1	10.3	21.9	68.5	79.6	
1991		5.26	15.9	10.1	21.7	68.4	105.3	UI, OC
1992		5.26	15.9	11.1	21.7	65.2	98.5	UI, OC
1993	VI-91	5.99	18.11	13.31	23.91	66.1	94.0	UI, OC, IRA, ETA

	Average Rates 4/ -----/		
	Plateau	Lower Rate Limit	Upper Rate Limit
1986	22.8	15.0	28.6
1987	23.0	15.2	28.8
1988	23.0	16.2	28.8
1989	23.0	16.2	28.8
1990	23.0	17.2	28.8
1991	22.7	16.9	28.5
1992	22.7	17.9	28.5
1993	25.87	21.07	31.67

-
- 1/ Rate Limits and Pivot Points based on July 1 - June 30 time frame.
- 2/ Prior to application of discount for Quality of FQ Service, When purchaser requests specified service.
- 3/ See page A-17 for explanation of abbreviations.
- 4/ Less the Discount for Quality of FQ service and assumes a 98.5% load factor.

Table A-9 Variable Rate Concept

VARIABLE INDUSTRIAL (VI) POWER

Instituted in 1986; all aluminum smelters elected service at this rate (vs. IP rate). Approximately 90% of the DSI load is for aluminum smelters.

The demand charges adjusted in rate filings does not change with the price of aluminum.

The VI rate varies with the price of aluminum. The parameters of the rate are:

Lower Rate Limit - set at 8.3 mills/kWh in 1986 and increases by 1 mill/kWh every 2 years on July 1, in addition to any adjustments made to the VI rate in rate filings.

Lower Slope - equals 1; i.e., for every 1 cent/pound decrease in aluminum price the price of electricity will decrease by 1 mill/kWh.

Lower Pivot Point - adjusted each year on July 1 using a weighted average of cost indices that measure changes in the following costs: electricity, alumina, labor, and other (inflation).

Plateau Energy Charge - energy charge that, when combined with a demand charge, equals the average melded IP standard rate.

Upper Pivot Point - adjusted each year on July 1 using a weighted average of the electricity cost index and other cost index. After 5 years, adjusted based on historical aluminum prices.

Upper Slope - equals 0.75; i.e., for every 1 cent/pound increase in aluminum price the price of electricity will increase by 0.75 mills/kWh.

Upper Rate Limit - set initially at 21.9 mills/kWh, and adjusted in rate filings.

The VI rate as applied for billing purposes is determined each month based on the average price of aluminum in U.S. markets lagged three months. The average price of aluminum in U.S. markets is defined as the average U.S. Transaction Price reported for the month by "Metals Week."

Table A-10
Average Rate by Rate Schedule
Industrial Firm Power and Predecessor Rates 1/

Effective Date	Rate Schedule	Actual Average Rate <u>2/</u> (m/kWh)
09/18/39	C-2, C-3	2.5
03/01/46	C-4	2.2
2/20/65	C-5	2.1
12/20/74	IF-1, MF-1	2.8
12/20/79	IF-2 <u>3/</u>	5.3
07/01/81	IP-1 <u>3/</u>	13.8
10/01/82	IP-2 <u>3/</u>	23.6
11/01/83	IP-83	24.7
07/01/85	IP-85	19.6
10/01/87	IP-87	23.2
10/01/89	IP-89	23.2
10/01/91	IP-91	23.5 <u>4/</u>

- 1/ Prior to IF-1, most large purchasers used the C rate schedules, including large PUDs and municipalities, as well as IOUs and DSIs. IF-1 and subsequent rate schedules were used only by DSIs. In 1986, aluminum DSIs began using the new VI-86 rate schedule.
- 2/ Average rates are calculated by dividing revenues by MWhs sold under each rate schedule. Note that IF-2, IP-1, IP-83, and IP-85 rate periods were short and included more of one season than the other; average rates are skewed due to seasonality of rates. Calendar year Generation and Sales reports were used.
- 3/ No sales made under the MF-2, MP-1, or MP-2 rate schedules.
- 4/ Rate continues into 1993, therefore statistics on revenues and MWhs are not yet complete. Rate reflects revenues and MWhs through December 1992 only.

Table A-11
Average Annual Rates
Industrial Firm Power and Predecessor Rates 1/

Calendar Year	Avg. Rate <u>2/</u> (mills/kWh)	Calendar Year	Avg. Rate <u>2/</u> (mills/kWh)
1939	2.0	1966	2.1
1940	2.1	1967	2.1
1941	2.1	1968	2.1
1942	2.2	1969	2.2
1943	2.3	1970	2.1
1944	2.4	1971	2.1
1945	3.1	1972	2.1
1946	2.4	1973	2.2
1947	2.2	1974	2.1
1948	2.1	1975	3.0
1949	2.2	1976	3.2
1950	2.2	1977	2.2
1951	2.1	1978	2.6
1952	2.1	1979	3.0
1953	2.1	1980	5.1
1954	2.2	1981	7.5
1955	2.1	1982	19.3
1956	2.1	1983	24.5
1957	2.1	1984	25.3
1958	2.1	1985	20.2
1959	2.2	1986	20.2
1960	2.1	1987	24.2
1961	2.2	1988	23.2
1962	2.2	1989	23.2
1963	2.2	1990	23.4
1964	2.1	1991	23.0
1965	2.1	1992	23.1

1/ Rate schedules reflected in this table include C-2 through C-5, IF-1 through IP-91. Prior to 1975, most large purchasers used the C-2 through C-5 rate schedules, including large PUDs and municipals, as well as IOUs and DSIs. All sales under these rate schedules are reflected in this table. 1975 and after, rate schedules IF-1 through IP-87 were used only by DSIs. In 1986, aluminum DSIs began using the new VI-86 rate schedules; sales under the VI rate are not included in this table.

2/ Average rates are calculated by dividing revenues by MWhs sold.

Table A-12
Annual BPA Wholesale Firm Power Sales
to Industrial Customers 1/

Calendar Year	MWhs	Revenues (\$)	Avg. Rate	Calendar Year	MWhs	Revenues (\$)	Avg. Rate
1939	7,181	14,113	2.0	1966	16,392,115	33,198,705	2.0
1940	95,177	196,447	2.1	1967	18,641,497	37,945,323	2.0
1941	1,241,493	2,562,261	2.1	1968	20,382,115	41,570,898	2.0
1942	2,869,137	6,125,557	2.1	1969	24,293,295	49,583,082	2.0
1943	5,308,354	12,202,299	2.3	1970	23,261,374	47,488,241	2.0
1944	6,037,377	15,060,504	2.5	1971	22,386,892	45,564,164	2.0
1945	4,645,864	15,314,404	3.3	1972	23,075,976	46,754,719	2.0
1946	3,417,337	8,196,764	2.4	1973	21,446,654	43,613,826	2.0
1947	5,338,957	11,880,457	2.2	1974	24,196,546	49,041,379	2.0
1948	6,161,236	13,207,445	2.1	1975	24,798,890	74,784,658	3.0
1949	6,493,622	13,938,756	2.1	1976	26,783,825	84,938,127	3.2
1950	7,481,459	15,930,122	2.1	1977	22,761,704	51,146,151	2.2
1951	7,551,535	15,744,175	2.1	1978	27,594,005	73,309,827	2.7
1952	7,006,678	14,660,548	2.1	1979	24,716,044	73,329,159	3.0
1953	8,434,630	17,409,393	2.1	1980	24,806,260	127,265,893	5.1
1954	9,363,055	19,274,197	2.1	1981	27,488,731	207,400,374	7.5
1955	10,591,311	21,689,397	2.0	1982	19,706,767	379,619,702	19.3
1956	12,184,320	24,594,799	2.0	1983	20,756,853	466,553,706	22.5
1957	11,375,760	22,969,503	2.0	1984	25,697,589	638,333,134	24.8
1958	9,469,024	19,388,379	2.0	1985	21,541,979	430,159,050	20.0
1959	10,562,817	21,230,064	2.0	1986	19,365,129	377,745,897	19.5
1960	10,687,068	21,297,955	2.0	1987	21,660,203	483,087,478	22.3
1961	10,427,999	21,055,379	2.0	1988	26,091,925	739,660,051	28.3
1962	10,741,134	21,612,308	2.0	1989	26,333,505	726,677,323	27.6
1963	11,628,598	23,236,305	2.0	1990	27,242,999	615,970,404	22.6
1964	13,370,685	26,462,203	2.0	1991	27,114,151	561,608,054	20.7
1965	14,889,567	29,749,179	2.0	1992	23,547,077	422,181,758	17.9

1/ Includes all firm, nonfirm, and interruptible power purchased exclusively by BPA's industrial customers, including aluminum smelter DSIs under the VI rate schedule (1986-Present).

Table A-13
BPA Nonfirm Energy Rate Schedules

	Rate Schedule	Energy Rates			Notes <u>1/</u>
		Standard (mills/kWh)	Contract	Other	
1939	H-1	2.5			
1940					
1941					
1942	H-2	2.5			
1943					
1944					
1945					
1946	H-3	2.5			
thru					
1965					
1966	H-4 <u>2/</u>	2.5			
thru					
1974					
1975	H-5	3.5 W 3.0 S <u>4/</u>			UI <u>3/</u>
thru					
1979					
1980	H-6	5.5		4.5 to 6.5 <u>6/</u>	
1981	NF-1	Resource Cost <u>5/</u>	9.6	5.0 to 6.5 <u>6/</u>	
1982	NF-2	18.2	11.2	9.0 <u>7/</u>	
1983	NF-83	18.5	13.9	11.0 <u>7/</u>	
1984					
1985	NF-85	22.2	18.1	7.0 and 12.8 <u>8/</u>	GDS, IC
1986	NF-85 Modified	7.0 to 22.2	18.1	7.0 to 22.2 <u>9/</u>	GDS, IC
1987	NF-87	up to 21.6	14.9	<u>10/</u>	GDS, IC
1988					
1989	NF-89	up to 21.6	14.9	<u>10/</u>	GDS, IC
1990					
1991	NF-91	up to 22.9	18.1	<u>10/</u>	GDS, IC
1992					
1993	NF-91	up to 26.89	14.26	<u>10/</u>	GDS, IC, IRA, ETA

- 1/ UI: Unauthorized Increase charge, \$.10/kW-mo.
GDS: Guaranteed Delivery Surcharge.
IC: Intertie Charge (1.2 m/kWh, NF-85; 1.4 mills/kWh, NF-87 and NF-89; 2.1 m/kWh, NF-91, 3.11 m/kWh, NF-93).
IRA: Interim Rate Adjustment.
ETA: Energy Tax Adjustment.
- 2/ S-1 (Wholesale Excess Energy) also available for nonfirm energy sales from 1966-1974, at a rate of 2.0 mills/kWh.
- 3/ Nonfirm energy became available for sale outside the region beginning in 1975.
- 4/ H-5 rates were seasonally differentiated Energy seasons are: Winter: Sep-Mar; Summer: Apr-Aug.
- 5/ NF-1 allowed BPA to sell at a price no higher than the cost of the resource used to provide the energy.
- 6/ Non-thermal displacement on-peak rate. Off-peak rate: 4.5 m/kWh (H-6); 5.0 m/kWh (NF-1).
- 7/ Spill rate.
- 8/ Low cost (oil fired) and high cost displacement rates.
- 9/ High cost displacement rate.
- 10/ Market expansion rate - any offered rate below the standard rate in effect.

Table A-14
Average Rate by Rate Schedule
Nonfirm Energy Rates

Effective Date	Rate Schedule	Actual Average Rate ^{1/} (mills/kWh)
09/18/39	H-1	2.5
01/01/42	H-2	2.5
03/01/46	H-3	2.5
12/20/65	H-4, S-1	2.0 ^{2/}
12/20/74	H-5	3.3
12/20/79	H-6	7.1
07/01/81	NF-1	7.4
10/01/82	NF-2	10.1
11/01/83	NF-83	13.9
07/01/85	NF-85	11.4
10/01/87	NF-87	15.6
10/01/89	NF-89	14.8
10/01/91	NF-91	15.01 ^{3/}

^{1/} Average rates are calculated by dividing revenues by MWhs sold under each rate schedule.

^{2/} Both rate schedules H-4 and S-1 in effect for nonfirm sales during this rate period.

^{3/} Rate continues into 1993, therefore statistics on revenues and MWhs are not yet complete. Rate reflects revenues and MWhs through December 1992 only.

Table A-15
Annual BPA Wholesale Nonfirm Power Sales 1/

Calendar Year	MWhs	Revenues (\$)	Avg. Rate	Calendar Year	MWhs	Revenues (\$)	Avg. Rate
1939	11,382	28,456	2.5	1966	574,106	1,208,913	2.1
1940	109,139	275,816	2.5	1967	371,247	775,921	2.1
1941	37,382	97,238	2.6	1968	1,570,450	3,162,812	2.0 <u>2/</u>
1942	86,005	215,068	2.5	1969	1,599,593	3,217,959	2.0
1943	176,076	440,190	2.5	1970	506,622	1,030,974	2.0
1944	400,250	1,000,625	2.5	1971	1,985,201	4,003,396	2.0
1945	270,377	675,942	2.5	1972	888,222	1,807,292	2.0
1946	168,705	421,793	2.5	1973	127,333	265,555	2.1
1947	162,013	405,064	2.5	1974	810,684	1,628,372	2.0
1948	101,272	253,179	2.7	1975	12,553,773	41,935,728	3.3
1949	85,928	214,819	2.5	1976	20,014,673	68,069,427	3.4
1950	109,975	274,938	2.5	1977	268,119	882,544	3.1 <u>3/</u>
1951	103,187	257,969	2.5	1978	14,445,115	47,087,477	3.3
1952	142,155	355,389	2.5	1979	5,116,606	15,308,968	3.0 <u>4/</u>
1953	116,283	290,707	2.5	1980	7,956,605	51,706,449	6.5
1954	127,584	318,961	2.5	1981	15,758,296	122,369,607	7.8
1955	116,027	290,068	2.5	1982	25,159,052	200,737,408	8.0
1956	106,284	265,711	2.5	1983	27,675,549	272,439,160	9.8
1957	106,224	265,559	2.5	1984	19,286,479	218,260,492	11.3
1958	88,093	220,232	2.5	1985	13,297,388	239,569,111	18.0
1959	75,620	189,050	2.5	1986	16,313,119	171,157,497	10.5
1960	89,591	223,979	2.5	1987	4,725,002	66,596,449	14.1
1961	99,977	249,945	2.5	1988	937,970	16,216,627	17.3
1962	115,252	288,144	2.5	1989	4,330,345	65,763,649	15.2
1963	108,200	270,504	2.5	1990	12,481,254	211,739,191	17.0
1964	143,967	361,360	2.5	1991	14,469,110	185,831,554	12.8
1965	134,603	336,492	2.5	1992	1,879,750	28,211,672	15.0

1/ Average rates are calculated by dividing revenues by MWhs sold.

2/ From 1966-1974, nonfirm sales were made under both the S-1 and H-4 rate schedules. The S-1 energy rate was 2.0 mills/kWh.

3/ About 1500 MW of new generation came on line in 1975, increasing sales substantially.

4/ Excludes "negative" nonfirm sales to California. Including these sales, the average NF rate for 1977 would be .8 mills/kWh.

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