DOCUMENTATION FOR THE LOADS AND RESOURCES STUDY

VOLUME 1

JUNE 1996

WP-96-FS-BPA-01A

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Volume 1

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TABLES

CHARTS

COMMONLY USED ACRONYMS

AC	Alternating Current
ACME	Accelerated California Market Estimator (computer program)
AFUDC	Allowance for Funds Used During Construction
aMW	Average Megawatt
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
ASM	Aluminum Smelter Model
BASC	BPA Average System Cost
BTU	British Thermal Unit
CE	Emergency Capacity (rate)
CF	Firm Capacity (rate)
CO-OP	Co-operative Electric Utility
COB	California-Oregon Border
COE	United States Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CWIP	Construction Work In Progress
CY	Calendar Year (Jan - Dec)
DC	Direct Current
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
DSM	Demand-Side Management
EA	Environmental Assessment
ECC	Energy Content Curve
EIS	Environmental Impact Statement
ET	Energy Transmission (rate)
F & O	Financial and Operating Reports
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
FPS	Firm Power Products and Services (rate)
FPT	Formula Power Transmission (rate)
FSEA	Federal Secondary Energy Analysis
FY	Fiscal Year (Oct - Sep)
GCPs	General Contract Provisions
GRSPs	General Rate Schedule Provisions
GTRSPs	General Transmission Rate Schedule Provisions
IDUEIS	Intertie Development and Use Environmental Impact Statement
IE	Eastern Intertie Transmission (rate)

IN	Northern Intertie Transmission (rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IR	Integration of Resources (rate)
IRE	Industrial Replacement Energy
IS	Southern Intertie Transmission (rate)
ISAAC	Integrated System for Analysis of Acquisitions (computer program)
ISC	Investment Service Coverage
KV	Kilovolt (1000 volts)
KW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LOLP	Loss of Load Probability
LTIAP	Long-Term Intertie Access Policy
M/kWh	Mills per kilowatthour
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
MW	Megawatt (1 million watts)
MW-miles	Megawatt-miles
MWh	Megawatthour
MT	Market Transmission (rate)
NEPA	National Environmental Policy Act
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (computer program)
NOB	Nevada-Oregon Border
NR	New Resource Firm Power (rate)
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OY	Operating Year (Jul - Jun)
PA	Public Agency
PIP	Programs in Perspective
PF	Priority Firm Power (rate)
PMDAM	Power Market Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PSW	Pacific Southwest
PURPA	Public Utilities Regulatory Policies Act
PUD	Public or Peoples' Utility District
RAM	Rate Analysis Model (computer model)
REVEST	Revenue Estimate (computer program)

ROD	Record of Decision
RP	Reserve Power (rate)
RPSA	Residential Purchase and Sale Agreement
SAM	System Analysis Model
SI	Special Industrial Power (rate)
SPM	Supply Pricing Model (computer program)
SPOM	Surplus Power-Open Market
SS	Share-the-Savings Energy (rate)
TGT	Townsend-Garrison Transmission (rate)
UFT	Use of Facilities Transmission (rate)
USBR	United States Bureau of Reclamation
VI	Variable Industrial Power (rate)
VOR	Value of Reserves
WNP	Washington Public Power Supply System (Nuclear) Project
WPPSS	Washington Public Power Supply System
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WSCC	Western Systems Coordinating Council

1. INTRODUCTION

This volume contains the Documentation associated with the economic and load forecasts for Bonneville Power Administration's (BPA) 1996 Final Rate Proposal. The Documentation is used to support the Loads and Resources Study (Study) (WP-96-FS-BPA-01). The Documentation and the Study reflect all of the load and resource assumptions used for the 1996 Final Wholesale Power and Transmission Rate Proposals.

2. OVERVIEW OF BPA'S ECONOMIC AND LOAD FORECASTING PROCESS

2.1 Economic Forecasting Process

BPA prepares economic and demographic projections of the Pacific Northwest in support of load forecasting requirements and resource acquisition programs. A midterm forecast (5-10 years) is prepared approximately once a year and updates to the forecast are prepared periodically to provide BPA with the most current information. The purpose of the forecast is to predict baseline growth trends in employment and population as well as focus on near-term projections to capture fluctuations in regional business cycles.

In support of the midterm forecasts, BPA has designed and developed the Regional Economic Model of the Pacific Northwest (REM) to forecast economic and demographic trends and cycles. The REM is actually a set of three economic models. These models of Washington, Oregon, and Idaho run independently and the results are then summed to create regional totals. However, the states are theoretically and conceptually related from the standpoint of macroeconomic impacts.

2.1.1 Forecast Process. The REM requires two types of data input: historical data for endogenous and exogenous terms and forecast data for exogenous terms. Endogenous or dependent terms are the regional variables that the REM solves and forecasts. They are the variables on the left-hand side of the model's mathematical equations. Exogenous or independent terms are variables on the right-hand side of the model's equations. They are predetermined variables which have already been projected for the forecast period. Also included on the right-hand side are some endogenous variables which capture the simultaneous relationships between some of the model equations. Typically, exogenous variables are national terms provided by Wharton Econometric Forecasting Associates Group, Inc. (WEFA).

Historical regional and national data for model estimation come from several sources. Employment and wage data are from the Bureau of Labor Statistics, income data are from the Bureau of Economic Analysis, and demographic data are from the U.S. Bureau of the Census.

The REM model equations define the historical relationships between regional economic and demographic concepts and national factors and trends. These equations are estimated over a significant historical time period and provide the technical relationships between the endogenous forecast variables and the exogenous terms. WEFA's projections for the U.S. provide the national macroeconomic and demographic assumptions and conditions that are used to derive the regional projections produced by REM. Timber harvest forecasts provided by the U.S. Forest

Service are also used to help derive employment in the lumber and wood products industry. Load and output estimates for the aluminum DSIs (BPA's Direct Service Industries) are used to derive employment levels for the primary aluminum employment forecast. A model-driven regional forecast is obtained by feeding the exogenous variables into the REM.

The REM produces detailed employment, income and demographic projections. These projections are reviewed by BPA industry analysts to incorporate information that is unique to industries in the Pacific Northwest region. Because models assume that historical relationships will remain relevant in the future, some information may not be properly characterized in the forecast when recent and clearly expected events differ from historical trends. These deviations may be caused by policy decisions or structural differences between regional and national trends. To overcome these limitations, the industry analysts may fine tune the model-driven forecast to produce the final forecast.

As part of BPA's Quarterly financial review process, the forecasts are reviewed and updated. The reviews ensure that the forecasts are tracking with new, revised or rebenchmarked data. The reviews also may include validity checks on major assumptions and on macroeconomic forecasts. If data, assumptions, or conditions have changed materially, the basic forecasts are revised in aggregate to reflect the new information.

2.1.2 Model Design The same basic model and equation structures are used in the design and development of the three state models. Income, wages, population, and employment provide the major model underpinnings. These components are joined to generate the dynamic links in the model, creating a "block-recursive" structure with simultaneous components. The theoretical design and functional form of individual model equations are similar across state models, but details differ somewhat because of sub-regional differences in economic and demographic conditions and structural relationships.

The REM equations for each state have a theoretical structure that is similar to the models used by State Revenue economists in Washington, Oregon, and Idaho. This basic structure is also used in similar regional forecasting models operated by national forecasting services such as Data Resources, Inc. (DRI) and WEFA.

Income in the model is specified in broad categories that match National Income and Product Accounts (NIPA) income concepts as reported by the U.S. Department of Commerce. Total income in the state is defined as the sum of total Salary Disbursements; Other Labor Income; Transfer Payments; Farm and Nonfarm Proprietors' Income; Dividends, Interest, Rent; and "Resident Adjustment"; minus Social Security Insurance Contributions.

Each income component is specified in a separate econometric equation, transformation, or identity and is estimated separately because each is thought to react differently to changes in economic trends, policy choices, and business cycles. The income categories are specified in the following general forms for each state:

Other Labor Income = f (state wages and salaries, U.S. other labor income)

Social Security Taxes = SSI tax rate * (state wages and salaries + 2 * proprietors' income)
Transfer Payments = f (U.S. unemployment benefits, U.S. retirement benefits)
Farm Proprietors' Income = f (U.S. farm proprietors' income)
Nonfarm Proprietors' Income = f (state per capita income, U.S. nonfarm proprietors' income)
Dividends, Interest, and Rent = f (U.S. per capita dividend, interest, and rent)
Resident Adjustment = state earned income * adjustment rate

The state wage and salary components are specified either econometrically or with identity equations. Wages and salaries are calculated for the manufacturing sector as a whole; the commercial sector as a whole; a combination of construction and mining; state and local government; Federal civilian government; and Federal military. These industry groupings assume that wages and salaries within each are similarly influenced in the aggregate for these sectoral combinations. The wage and salary combinations are then calculated as total wage bills for the sectors by multiplying the wage rate by employment. The standard functional form of wage rate equations in each state model is given by the following generalized form:

Manufacturing = f(state hourly manufacturing wage rate, state manufacturing employment, state hours worked, labor market constraint)
Commercial = f (Commercial employment-weighted U.S. wage and salary rate, labor market constraint)
Construction and Mining = f (Construction and mining employment-weighted U.S. wage and salary rate, labor market constraints)
Govt., Fed. Civilian = f (U.S. Federal civilian government wage rate)
Govt., Fed. Military = f (U.S. Federal military wage rate)
Govt., State and Local = f (U.S. average state and local government wage rate, state income, state commercial wage and salary rate)

Population in the model is defined as the sum of natural population increases and net migration. The REM incorporates conventional methodologies in accounting for natural population increases and migration by age. An age-cohort component method is used in determining population growth and aging of the age groups over the forecast period. Births are calculated as a function of age cohorts, state-level birth rates, and the trend in births at the U.S. level. A migration forecast based on economic conditions and trends is either added to or subtracted from natural population increases to obtain the total population per year. The age cohort mix of migrants is determined according to relationships estimated by the Washington State Office of Financial Management.

Households are derived from population and persons-per-household estimates. The estimates for person-per-household use state-level data for history. For the forecast, the person-per-household values are extended from the last historical year and varied at the same rate of change as projected by the U.S. Bureau of the Census.

The migration component is linked directly to employment. Relative income and employment growth determines expected migration. The population forecast defines the available labor supply and, in conjunction with wages, imposes constraints on employment growth.

Employment is specified in each state model for most two-digit manufacturing U.S. Standard Industrial Classifications (SIC's) and for each one-digit nonmanufacturing SIC. Some nonmanufacturing sectors are further disaggregated. The manufacturing industries included in the REM are Food Processing (SIC 20), Textiles (22), Apparel (23), Lumber and Wood Products (24), Furniture and Fixtures (25), Pulp and Paper (26), Printing and Publishing (27), Chemicals (28), Petroleum (29), Rubber and Plastics (30), Leather Products (31), Stone, Clay and Glass (32), Primary Metals (33), Fabricated Metals (34), Nonelectrical Machinery (35), Electrical Machinery (36), Transportation Equipment (37), Instruments (38), and Miscellaneous Manufacturing (39).

The nonmanufacturing industries in the model include Transportation and Public Utilities (TPU); Finance, Insurance, and Real Estate (FIRE); Federal Civilian Government; Federal Military; State and Local Government; Health Services; Nonhealth Services; Retail Trade; Wholesale Trade; Construction; and Mining.

The employment sector is conceptually divided into three categories: *base industries, local industries, and mixed industries*. The major linkages to the model occur through the employment sector where state income, state wages, state population, regional resource constraints, and U.S. macroeconomic assumptions tie together in the model. The extent to which these factors influence a particular industry determines whether the industry is considered basic, local, or mixed.

Traditionally, basic industries are mining and the manufacturing industries which service and/or are heavily influenced by national market conditions. The agricultural sector is often considered a basic industry, but the REM does not model farm employment. Instead it forecasts wages and salary farm income based on national assumptions. The impact of agriculture is modeled through its income contributions. In the model, basic manufacturing industries are lumber and wood products, paper and pulp, aluminum smelting, transportation equipment and electronics. These industries are modeled using primarily macroeconomic drivers.

Local industries are essentially all the nonmanufacturing sectors (excluding Federal government and military employment) and a few manufacturing industries which mostly service the local economy. The manufacturing industries in the region which are considered to be locally driven are: furniture and fixtures; rubber and plastics; stone, clay and glass; printing and publishing; and miscellaneous manufacturing.

The remaining manufacturing industries not categorized as either local or base industries are regarded as mixed industries. The mixed industries generally serve a local market and a part of the U.S. They are significantly influenced by both national and regional trends. For example, they include food processing, textile, apparel, non-aluminum primary metals, chemicals, petroleum products, and fabricated metals.

Each employment category has a separate and unique equation, but a general form for each of the equations can be broadly characterized as follows:

Basic = f(U.S. macroeconomic factors, resource constraint [if applicable], employment-weighted productivity index, weighted industrial output)

Local = f(state population, state income, inter-industry relationships, weighted-productivity index, weighted industrial output, state wage rate)

Mixed = f(weighted productivity index, weighted industrial output index, inter-industry relationships, U.S. macroeconomic factors, state income, state population, state wage rates)

Not all factors will appear in each equation and some specific variables may not be listed. The actual specification depends on the unique structure of the industry, its market and product mix, and its relationship to other regional, national and international market factors.

2.1.3 Assumptions The employment forecast used in the preparation of the load forecasts for the 1996 final rate proposal is based on WEFA's February 1995 Long-Term U.S. forecast of national macroeconomic and demographic trends. A summary of the national indicators from this forecast is presented in Table 1.

Insert Table 1 (Table1f.xls)

2.1.4 Results The employment forecast by fiscal year for the Region is listed in Table 2. The table shows recent history and BPA's forecasts for total wage and salary employment for nonfarm employment in the Region (Washington, Oregon, and Idaho).

Table 2

Pacific Northwest Employment

	Historical Employment		Forecast Employment	
Fiscal Year	(Thousands)	(% Change)	(Thousands)	(% Change)
1992	3883.9	2.0%		
1993	3969.1	2.2%		
1994	4096.0	3.2%		
1995			4232.4	3.3%
1996			4276.3	1.0%
1997			4388.9	2.6%
1998			4465.7	1.7%
1999			4542.0	1.7%
2000			4614.8	1.6%
2001			4689.3	1.6%
2002			4764.2	1.6%
2003			4839.9	1.6%
2004			4918.0	1.6%

Source: BPA, Market Forecasting and Segment Analysis/MPMO
March 1995 Economic Forecast

2.2 Midterm Load Forecasting Process

BPA's midterm load forecasting process estimates total firm loads (with the exception of the DSI load forecast, which includes estimates of both firm and nonfirm load) by month. Each of the following customer groups is estimated separately: Non- and Small Generating Public Utilities (NSGPU), Generating Public Utilities (GPU), direct service industries (DSI) aluminum, DSI non-aluminum, investor-owned utilities (IOU), Federal agencies, and the United States Bureau of Reclamation (USBR).

In general, BPA's midterm load forecasts are designed to respond to and reflect near-term factors and events. The time horizon of these forecasts is usually 5 to 10 years. Depending upon the customer load to be estimated, all or some of the underlying economic, load, weather, and retail electricity price data are updated and the forecast is reviewed and revised over the course of the year.

BPA's midterm forecast, or portions of the forecast, is used principally for operational and financial purposes. For operational purposes, each year in January, the first four years of portions of the midterm load forecast are used in preparing BPA's forecast of Federal system loads for submittal to the Northwest Power Pool (NWPP) for the Pacific Northwest Coordination Agreement (PNCA) and the NWPP Operating Program. For financial purposes, portions of the midterm load forecast are used to estimate Federal system load projections for rate filing proceedings and for quarterly revenue estimation purposes.

2.3 Long-Term Load Forecasting Process

BPA jointly prepared long-term forecasts (20 years) of regional and Federal system loads with the Northwest Power Planning Council (NPPC) in April 1991. These long-term load forecasts are used to determine how much electricity the region and Federal system will need; to explore and define the uncertainty surrounding future resource needs; and to develop and support conservation and resource programs. In 1993, BPA produced a new long-term forecast for determining its load-resource balance. BPA’s 1993 forecast updated the economic assumptions from the April 1991 BPA/NPPC forecast, and it also utilized a modified version of the residential sector model. This 1993 forecast is used in the current rate proceeding to produce the long-term forecast of regional IOU energy sales. No long-term forecasts were used to produce the GPU, NSGPU, DSI, Federal agency, or USBR load forecasts for the current rate proceeding.

Details pertaining to the BPA/NPPC 1991 long-term load forecast are contained in the 1991 Northwest Conservation and Electric Power Plan, Volume II Part 1, May 1991.

2.4 Final Rate Proposal Midterm and Long-Term Forecasts

In the 1996 final rate filing studies, both the midterm and long-term forecasting processes were used to produce load projections for the period October 1996 through September 2001. BPA's August 1995 midterm load forecast was used for the NSGPU, GPU, DSI, Federal agencies, and USBR load projections. BPA’s 1993 long-term forecast, which updated the economic assumptions from the April 1991 BPA/NPPC joint forecast and utilized a modified version of the residential sector model, was used to produce projections of IOU loads in the 1996 final rate filing.

A Statistical Analysis Software System (SAS) based program entitled the Long-Term Output Program (LTOUT) transforms the long-term forecast of annual IOU sales into monthly load projections. The 1996 final rate filing forecast for the IOUs used information (e.g., monthly shaping of annual load and load factors) contained in the individual IOU load forecasts as submitted to the Pacific Northwest Utilities Conference Committee (PNUCC) for the March 1994 Northwest Regional Forecast of Power Loads and Resources (1994 NRF). LTOUT transforms sales to load using BPA's estimates of monthly transmission and distribution losses as a percentage of load for each customer class.

3. LOAD FORECASTS

3.1 Direct Service Industries

The Direct Service Industries (DSIs) are a group of 15 industrial firms operating 19 plants in the Pacific Northwest that purchase electric power directly from BPA. These plants primarily involve electricity-intensive industrial processes such as production of aluminum and other primary metals, pulp and paper, ferroalloys, and chlor-alkalies (see Table 3). For forecasting purposes, the DSIs are divided into aluminum and non-aluminum industries. Total aluminum DSI loads are forecasted by comparing the aluminum price forecast with the estimated production costs of each smelter and are then evaluated in light of historical smelter operations and other known individual smelter characteristics. BPA's share of the total aluminum DSI loads are estimated based on the load amounts reflected in the signed five-year block sales contracts and other anticipated block sales contracts and the minimum load criterion (80 percent of firm load) set by the U.S. DOE for DSIs to avoid incurring stranded investment charges. Total non-aluminum DSI companies are analyzed individually by BPA staff to develop load projections. BPA's share of the total nonaluminum DSI loads are estimated based on the same factors mentioned above for the estimation of BPA's share of the total aluminum DSI loads.

Table 3
Direct Service Industries

Industry	Companies
Primary Aluminum	Alcoa, Columbia Aluminum, Columbia Falls Aluminum, Northwest Aluminum, Intalco, Kaiser, Reynolds, Vanalco
Aluminum Fabrication	ACPC, Kaiser, Reynolds, Vanexco 1/ 2/
Magnesium/Ferrosilicon	Northwest Alloys 1/
Abrasives	Carborundum 2/
Titanium	Oremet
Nickel	Nickel Joint Venture
Pulp/Paper	Port Townsend Paper Co.
Chlor-Alkali	Georgia Pacific, Atochem
Calcium Carbide	Pacific Carbide 2/
Steel Plate	Gilmore Steel 3/

1/ Subsidiary of Alcoa
2/ Plants currently closed and dismantled
3/ No load placed on BPA at present time

3.1.1 Aluminum Smelter Load Forecasting Methodology Aluminum DSI loads are forecasted by comparing an aluminum price forecast with the estimated production costs for each smelter to estimate short-term economic viability of operations. If production costs approach or exceed the aluminum price for any given smelter, that smelter was considered to be at risk of closure. This initial assessment of the operating rates by smelter was then evaluated in light of historical smelter operations and other known smelter characteristics and modified to reflect this additional information. Other factors taken into consideration include information on the 1994 Brussels Agreement and world production levels, the competitive electricity market, BPA's waiver and release of the DSI top quartile, the load amounts in the signed five-year block sales contracts and other anticipated block sales contracts, the minimum load criterion (80 percent of firm loads) set by the U.S. DOE for DSIs to avoid incurring stranded investment charges, and BPA's understanding of the individual characteristics and business strategies of each company, including their proclivity to purchase power from alternative suppliers and power sales already contracted for with alternative suppliers. Smelters were analyzed individually to determine the way that each smelter would respond to these factors. The aluminum DSI load forecasts, energy and peak, are in Appendix 1 of this document.

3.1.1.1 Aluminum Price Forecast The aluminum price forecast is a variable that affects projections of DSI smelter loads. A lower price of aluminum tends to reduce expected aluminum production, electric loads, and resulting power sales revenues.

The projections of the U.S. transaction prices for aluminum are expressed in current dollars and average 83.5 cents/lb for FY 1997-1998, and 87.4 cents/lb. for FY 1997-2001. The price forecast is shown on Table 4 below.

Table 4

MEDIUM ALUMINUM PRICE FORECAST

cents/lb	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
FY94	51.7	50.4	52.9	57.0	61.6	62.3	61.9	64.0	67.8	72.7	71.2	77.8
FY95	83.8	91.9	91.5	100.4	93.8	88.7	90.4	84.5	83.0	81.5	80.0	78.5
FY96	78.0	78.0	79.0	80.0	80.2	80.3	80.5	80.7	80.8	81.0	81.2	81.3
FY97	81.5	81.7	81.8	82.0	82.2	82.3	82.5	82.7	82.8	83.0	83.2	83.3
FY98	83.5	83.7	83.8	84.0	84.3	84.5	84.8	85.0	85.3	85.5	85.8	86.0
FY99	86.3	86.5	86.8	87.0	87.2	87.3	87.5	87.7	87.8	88.0	88.2	88.3
FY2000	88.5	88.7	88.8	89.0	89.3	89.5	89.8	90.0	90.3	90.5	90.8	91.0
FY2001	91.3	91.5	91.8	92.0	92.3	92.5	92.8	93.0	93.3	93.5	93.8	94.0

Shaded areas are actual U.S. Transaction prices.

The historical aluminum prices reflect slower than average economic growth in the world and higher than desired primary aluminum inventory levels. Improvement in the world economy and accompanying increased demand for aluminum were slower than experienced after previous recessions. In addition, relatively high, and still increasing, inventory levels and high smelting capacity increases in 1992 and again in 1993, and continued high export levels from the former Soviet Union, kept prices from rising. In late 1994, aluminum prices rose rapidly as a result of the recovery in the world economy and aluminum demand, the stabilizing influence of the Brussels Agreement, and speculative activity by financial investors. Aluminum prices are forecasted to gradually decline from the high level of January 1995 as the Brussels Agreement unravels and production increases. Beginning January 1996, the aluminum price forecast is based on the marginal cost of a new smelter, 80 cents per pound. This price is escalated more slowly than the rate of inflation due to efficiency improvements in production technology.

3.1.1.2 Variable Industrial Rate For the period FY 1997 and beyond, it is assumed that a new customized Variable Industrial (VI) rate will be available to the DSIs. For details on the proposed new VI rate, see Kusaka, Ross and Cocks, WP-96-E-BPA-35 and WP-96-E-BPA-56.

3.1.1.3 Smelter Production Costs There are four categories of production costs: power, alumina, labor, and other costs. The basis for the cost estimates is a report by Resource Strategies, Inc. (RSI), one of BPA's aluminum industry consultants. Table 5 shows estimated smelter production costs for FY 1997 - 2001. The smelter production costs in Table 5 form the basis for the cost/price comparisons.

3.1.1.4 Short- to Medium-Term Net Operating Costs and Long-Term Cash Costs The electricity, alumina ore, labor, and other material costs all vary with the level of smelter production, and thus comprise the short- to medium-term net operating or variable production costs. In general economic theory, if the aluminum price falls below a smelter's variable production costs, the smelter is at risk of short-term temporary production cutbacks until prices recover. In the longer term, other non-variable costs such as capital servicing and corporate overhead must be paid if a smelter is to survive. Thus, the short-term variable plus capital servicing and corporate overhead costs comprise the long-term smelter cash costs. In the long term, if aluminum prices are not high enough for a smelter to recover its long-term cash costs, then it is assumed that the smelter is not economically viable and will be at risk of permanent closure. The basis for the total (federal and nonfederal) smelter load forecast is a metal price/smelter cost comparison. The smelter's net operating costs, or short- to medium-term variable costs, are considered for temporary closure decisions, and longer term cash costs for long-term permanent closure decisions. Smelter costs are estimated and are a principal but not sole determinant of smelter operations. Thus, judgmental adjustments are made, in addition to metal price/smelter cost analysis, to incorporate other non-cost related factors.

TABLE 5
OPERATING COSTS OF PRODUCTION
(Nominal $)

	FY 1997	**FY 1998**	**FY 1999**	**FY 2000**	**FY 2001**
Aluminum price (cents/lb.)	82.4	84.7	87.4	89.7	92.6
	cents/lb.	cents/lb.	cents/lb.	cents/lb.	cents/lb.
Columbia Falls Aluminum - Columbia Falls	66.2	67.6	69.0	70.5	71.9
Northwest Aluminum - The Dalles	67.2	68.5	69.9	71.3	72.6
Intalco - Ferndale	62.8	64.2	65.6	66.5	67.8
Columbia Aluminum - Goldendale	65.1	66.5	67.8	69.1	70.4
Reynolds - Longview	68.9	69.9	70.8	71.5	72.3
Kaiser - Mead	70.5	71.7	72.9	74.2	75.4
Kaiser - Tacoma	68.6	69.7	70.6	71.2	72.1
Reynolds - Troutdale	77.3	78.6	79.8	80.8	82.0
Vanalco - Vancouver	72.1	73.6	75.1	76.2	77.5
Alcoa - Wenatchee	64.5	65.8	67.0	67.8	69.0
AVERAGE (weighted):	68.1	69.4	70.6	71.7	72.9

3.1.1.5 Future Smelter Conservation and Load Reductions BPA's Conservation/Modernization (Con/Mod) program began in 1987 and effectively ended in 1991. No future conservation savings are expected as a result of this program. BPA studies indicate that the regional smelters have consistently made electric efficiency improvements over time in the absence of any BPA-sponsored conservation program. BPA studies show about 11-12 aMW of savings by regional smelters on an annual basis. These savings are offset by about 50 percent due to projected increases in electricity use due to the installation of pollution control equipment. It is assumed that smelter capacity (absolute maximum amount of electricity a given smelter can consume) is reduced by 6 aMW.

3.1.1.6 The Medium Case Load Forecast All regional smelters can recover their variable production costs with metal prices of 80 cents/lb., the long-run market equilibrium price. The metal price is an important, but not the sole determinant of regional smelter operations (as discussed in the preceding paragraphs). The regional smelters are assumed to be operating at full capacity through the year 2001, and it is assumed that BPA will serve most of this load. It is assumed that the Alcoa-Wenatchee smelter will displace all of its purchases from BPA with power from Chelan P.U.D. and that all of the other aluminum DSIs will purchase power from alternative suppliers for a portion of their loads. It is assumed that BPA will wheel the power purchased from alternative suppliers.

Table 6 summarizes the BPA and non-BPA load forecasts for FYs 1997 through 2001.

TABLE 6
Aluminum DSI Load Forecast

aMW	BPA Load	NonBPA Load
FY 1997	1632	1251
FY 1998	1632	1251
FY 1999	1632	1251
FY 2000	1632	1251
FY 2001	1632	1251

3.1.1.7 Peak and Firm Loads The forecasted loads for DSI smelters are in average megawatts (aMW) and therefore require the application of load factors in order to determine peak loads. To determine total peak loads, aluminum DSI average energy loads are divided by the load factor, assumed in this case to be 0.985 for the aluminum smelters. This load factor is based on normal operations for each plant. Under the new contracts, all loads placed on BPA by the smelters will be firm loads.

3.1.2 Non-aluminum DSI Load Forecast The load forecast for the non-aluminum DSIs was prepared on a plant-by-plant basis. For each of the plants, load forecasts were prepared based upon information collected on historical, current and future operating schedules, plant technology, and expected economic and market conditions. The forecast was further adjusted to reflect other factors such as the competitive electricity market, BPA's waiver and release of the DSI top quartile, the load amounts in the signed five-year block sales contracts and other anticipated block sales contracts, the minimum load criterion set by the U.S. DOE for DSIs to avoid incurring stranded investment charges, and BPA's understanding of the individual characteristics and business strategies of each company. Plants were analyzed individually to determine the way that each would respond to these factors. The non-aluminum DSI load forecasts, energy and peak, are in Appendix 1 of this document.

Total BPA energy load for the non-aluminum DSIs is projected to be 210 average megawatts (aMW) for the five-year rate period. Table 7 summarizes the BPA and non-BPA load forecasts for FYs 1997 through 2001.

TABLE 7
Nonaluminum DSI Load Forecast

aMW	BPA Load	NonBPA Load
FY 1997	210	97
FY 1998	210	97
FY 1999	210	97
FY 2000	210	97
FY 2001	210	97

3.1.2.1 Peak and Firm Loads The forecasted loads for non-aluminum DSIs are in average megawatts (aMW) and therefore require the application of load factors in order to determine peak loads. To determine total peak loads, each plant's energy load forecast is divided by the plant's historical load factor. These load factors range from .58 (ACPC) to .95 (Georgia Pacific) and are based on normal operations for each plant. Under the new contracts, all loads placed on BPA by the DSIs will be firm loads.

3.2 Non- And Small Generating Public Utility Loads

BPA uses a regional econometric modeling approach to predict non- and small generating public utilities' (NSGPU) loads. A single model produces an estimate of total NSGPU loads. The model form has remained essentially the same since its first use in BPA's 1987 rate filing. Changes include new and revised data, extension of the estimation period, and improved estimates of the monthly shaping of NSGPU loads. The utilities in the NSGPU loads are listed in Table 8.

3.2.1 Model Definition and Forecast Process A single-equation piecewise linear model is estimated for regional NSGPU loads incorporating four independent variables. The model is in the following form:

The Quantity of Electricity Demanded is a function of:

- average retail electricity price,
- nonagricultural employment,
- heating degree-days, and
- cooling degree-days.

In addition, the current model employs a lagged dependent variable and dummy variables for certain months in which weather does not appear to explain all the load variation.

Chart 1 illustrates the process for forecasting NSGPU loads. The first step in the process is to collect historical data for the dependent and independent variables. The data are used to statistically estimate a regional forecast model using ordinary least-squares regression techniques. Once forecasts of the independent variables are obtained, the model forecasts the NSGPU electricity load for the region.

3.2.2 Electricity Price Inputs The retail price of electricity is a significant factor influencing retail electricity consumption. Economic theory suggests that curtailment of use, increased efficiency of use (e.g., weatherization), and fuel switching are among the possible retail responses to higher electricity costs. While economic theory argues for the use of a marginal price variable, development of a complete and reliable marginal price series is virtually impossible given the aggregate nature of the historical load data being employed. Therefore, an average retail electricity price series was constructed and is used in the model to estimate the relationship between regional NSGPU load and retail electricity price.

3.2.2.1 Historical Construction of the historical retail electricity price series was as follows. Retail revenue and sales by utility are obtained from individual utility monthly Financial and Operating (F&O) Reports submitted to BPA. The data are summed to obtain the total NSGPU level, and then the total monthly sales revenue is divided by total regional monthly kWh sales. The quotient equals the monthly average regional retail electricity price. These data are converted to real 1994 mills per kWh by using the current implicit GNP deflator used in BPA's Supply Pricing Model (SPM). The resultant series is used in estimating the monthly electricity load model.

3.2.2.2 Forecast The retail electricity price forecast is developed using BPA's SPM. A discussion of the SPM is provided in section 3.19 of this document. Section 3.3 contains the nominal historical price series and the nominal and real forecasted price series. The deflator used to convert nominal historical prices to real prices is implied in the real/nominal price relationship in the forecast file.

3.2.3 Weather Inputs Due to the high saturation of electric space heating in the Pacific Northwest, variations in weather are closely correlated with changes in electricity consumption. Of the several weather variables available (such as average temperature, precipitation, heating degree-days, and cooling degree-days), heating and cooling degree-days were selected to explain the seasonal variation in loads due to weather.

3.2.3.1 Historical The historical degree-day data are derived from daily temperature data as reported by nine National Oceanic and Atmospheric Administration (NOAA) stations located throughout the region. The stations are in Astoria, Boise, Spokane, Richland, Missoula, Pocatello, Redmond, Seattle, and Salem. The station-level degree-day data are weighted by the percentage of regional residential and commercial customers adjacent to that station. These weights were developed in 1986 using 1985 data. The station-level degree-day data are contained in section 3.4 of this document.

3.2.3.2 Forecast The forecasts of the weather inputs (heating and cooling degree-days) are based on 31 years of daily temperature data for each of the nine stations in the region. The degree-day data are created as follows. For each of the nine stations, average daily minimum and maximum temperatures for each day of the year are calculated for the period 1958 through 1988 (i.e., n=31 for each day of the year). Given the minimum and maximum averages, heating and cooling degree-day data for each station are calculated for each day. Monthly average degree-day data for each station are calculated. The station-level data are then weighted, based on the percentage of regional residential and commercial customers adjacent to each of the weather stations. The station-level degree-day data are contained in section 3.4 of this document.

3.2.4 Economic Inputs The economic data used in developing the NSGPU model must be available at monthly frequencies with regular and timely updates. The variable selected to capture the regional economy's effect on the demand for electricity for the NSGPUs is regional total nonagricultural employment. Total nonagricultural employment is assumed to capture commercial and industrial sector activity, as well as residential activity, which is affected by household and firm income.

3.2.4.1 Historical Monthly historical employment data for Washington, Oregon, and Idaho are obtained from WEFA. The employment data are equivalent to the BLS 790 data series collected by the Bureau of Labor Statistics (BLS) in cooperation with each state's Employment Securities Departments. The state agencies are as follows: (1) Washington State - the Research and Statistics Section, Employment Security Department; (2) Oregon State - the Research and Statistics Section, Employment Division, Department of Human Resources; and (3) Idaho State - Bureau of Research and Analyses, Department of Employment. The monthly state-level data are summed to obtain the monthly regional employment variable needed to develop the NSGPU forecast model. See section 3.5 of this document.

3.2.4.2 Forecast Projections of total nonagricultural employment are derived using BPA's Regional Economic Forecasting Model (REM). REM, which contains state-level econometric models, was developed by BPA staff to assist in preparing quarterly employment projections for Washington, Oregon, and Idaho. The employment forecast is converted to monthly frequency using linear interpolation. The monthly employment figures are then seasonalized based on historical seasonal employment patterns. Finally, the total regional nonagricultural employment variable used in the forecast process is created by summing the three state-level projections. The state-level projections are in section 3.5 of this document. See section 2.1 for details pertaining to REM.

3.2.5 Load Inputs The historical load data series must be complete and of sufficient duration to support a projection of monthly loads for approximately 5 to 10 years. The data also must reflect the total amount of electricity used by the ultimate consumers (residential, commercial, industrial, and other) served by the utilities within the region. Furthermore, these historical data must represent "total" system loads, not "net" (reduced by resources and purchases of non-BPA power) loads.

The historical load data used in modeling NSGPU loads were extracted from BPA's Automated Energy Sales and Statistics Summary (AESSS) data base, maintained by BPA’s Billing Operations Group. The data reflect BPA's wholesale power sales at each utility customer's points-of-delivery (POD). For those utilities that have access to electricity other than that sold by BPA, the portion of load met by "other" resources (i.e., own-generation, contract resources, or purchases of non-BPA power) is added to the BPA wholesale power data to obtain the NSGPU total system load requirements. The data include utility distribution losses but exclude Federal transmission losses.

Many of BPA's wholesale billings do not correspond to calendar months. Monthly loads for these utilities must be adjusted to calendar month equivalents to correlate the historical load data with the appropriate calendar month employment, retail electricity price, and weather data. This adjustment is accomplished by using weighted averages. The average loads for a given billing month are weighted by the number of days of that billing month which fall in the corresponding calendar month and, when necessary, these weighted loads are added (subtracted) to (from) the previous (subsequent) month's similarly weighted loads to yield calendar month equivalent loads. As an example, Table 9 shows the monthly megawatt adjustments for calendar year 1989.

The regional historical loads also are adjusted to account for conservation savings attributed to BPA's conservation programs. The monthly actual historical NSGPU loads are increased by about 80 percent of the amount of conservation that has been estimated to have occurred as determined by BPA's Conservation and Energy Services Group. If the effects of programmatic conservation were not removed, the retail electricity price coefficient estimated in the model would be overstated: electricity prices rose during the same time period (early to mid-1980s) that significant conservation efforts began. The remaining 20 percent of conservation estimates are considered to be price-induced and are not included in the conservation adjustment to historical loads. Price effects are assumed to be captured in the retail electricity price coefficient included in the model. See section 3.23 of this document.

In October 1989, Oregon Trail Electric Consumers Cooperative (OTECC) began serving an area previously served by the privately owned CP National Corporation (CP National). In order to achieve appropriate CP National load levels in the forecast period, the historical loads in the entire estimation period are adjusted to account for OTEC's load. A historical and estimated monthly load data series was created for OTEC using CP National data. These data were then added to the NSGPU historical load series.

The adjusted historical monthly load series for the period January 1980 through December 1993 was used to develop the forecast of total NSGPU loads used in this rate filing (see section 3.6 of this document).

3.2.6 Dummy Variables Over the estimation period, certain months were consistently over- or under-forecasted. To more accurately reflect the monthly shaping, dummy variables were introduced. These variables had the effect of reapportioning the loads between the months without affecting the annual load levels.

3.2.7 Model Estimation As illustrated in Chart 1, after the historical input data are obtained, the next stage in developing a forecast is to estimate the model. Given the theoretical form described previously, the historical relationships between the demand for electricity and weather, employment, and retail electricity price are statistically determined.

The model estimation is conducted using the Statistical Analysis System (SAS) software package developed by the SAS Institute, Inc. The SAS code for the NSGPU forecast model is in section 3.7 of this document.

The model represents a demand equation given the following criteria: (1) theoretical structure; (2) availability and reliability of data (historical and forecasted); (3) appropriate signs and reasonable magnitude of the equation's coefficients; (4) statistical significance of the variables (t-statistics); (5) overall statistical fit of the model to the historical data (R-square); and (6) comparison of the actual and fitted values (Mean Square Error). The model is segmented by the heating degree-day value for the month. Depending upon the heating degree-day value, a different intercept and coefficients for the heating degree-day and cooling degree-day variables are used to calculate the forecasted load. Within each segment the model is linear. Because of this segmentation and linearity within segments the model is called a "piecewise" linear model.

The model specification selected to forecast NSGPU loads is identified in Table 10. Definitions of the variables used in the model are listed in Table 11. Tables 12 and 13 present the mean error and percent difference (net and absolute) between the actual and estimated values over the model estimation period, January 1980 through December 1993.

Once the model is estimated, the next stage in the NSGPU forecasting process is to forecast the independent variables (retail electricity price, employment, and weather). Given these inputs, the estimated model is used to generate a forecast of total NSGPU loads (refer to Chart 2).

3.2.8 Energy Load Forecast In the final stage of the total load forecasting process, the forecasted independent variables are input in the model to produce a regional forecast of NSGPU loads. These projected loads are then reduced by: (1) estimated future savings resulting from BPA conservation programs and (2) estimated future savings due to additional conservation, conservation reinvention, and customer-funded conservation. See section 3.21 of this document.

Additions were also made to the NSGPU forecast to reflect (1) the three NSGPU customers newly served by BPA (City of Plummer, Modern Electric Company, and City of Chewelah) and not included in historical loads, and (2) expected increases in regional industry not captured in model estimation periods.

The NSGPU load forecasting model predicted loads through September 2003. The forecast was extended through September 2005 using year-to-year growth rates averaged by month over the last two years of the forecast.

After implementing the above adjustments, the forecast represents a projection of loads that have to be met by generating resources (refer to Chart 2) and/or by purchases of non-BPA power (see section 3.15 of this document). The final total NSGPU forecast is in Appendix 1 of this document.

3.2.9 Peak Load Forecast A noncoincidental peak load forecast is used for revenue projections and capacity rate determinations. The monthly NSGPU peak forecast is developed by applying monthly load factors to the monthly energy forecast. The monthly average load factors were developed from historical BPA billing records for the period June 1984 through May 1994. The final peak load forecast is provided in Appendix 1 of this document.

3.2.10 Disaggregation The NSGPU forecast is disaggregated to utility level by developing ratios representing each utility's share of monthly total NSGPU loads based on a combination of historical information and the forecasts contained in BPA's Sum of Utilities (SOU) database. The SOU contains forecasts prepared by BPA field economists for each of the NSGPUs in the region. The individual utility load forecasts produced by disaggregation are contained in section 3.8 of this document.

3.9 Generating Public Utility Loads

The wholesale rate filing requires a monthly total load forecast for the generating public utilities (GPUs). The nine utilities included in this group are listed in Table 14. The GPU load forecast is compared to the GPU resources to determine a projection of energy purchases from BPA by the GPUs. This information is then used in the rate development process.

In 1988 BPA developed an econometric model to forecast total GPU loads. The model form is similar to the NSGPU model form discussed in section 3.2.1. BPA's GPU model allows an independent forecasting capability. BPA can update its load estimates as necessary. In addition, the NSGPU and GPU forecast models are based on the same general assumptions regarding the regional economic outlook, providing BPA with consistency in its projection of total public loads.

3.9.1 Model Definition and Forecast Process A single-equation linear model is estimated for regional GPU loads incorporating four independent variables and 5 monthly dummy variables. The model is in the following form:

The Quantity of Electricity Demanded is a function of:

- average retail electricity price,
- nonagricultural employment,
- heating degree-days,
- cooling degree-days.

Chart 3 illustrates the process for forecasting total GPU loads. In general, this process is similar to the NSGPU forecasting process. As the flow chart illustrates, the first step in the process is to collect historical data for the dependent and independent variables. The data are used to statistically estimate a regional forecast model using ordinary least-squares regression techniques. Once forecasts of the independent variables are obtained, the model forecasts the GPU electricity load for the region.

3.9.2 Electricity Price Inputs

3.9.2.1 Historical Construction of the retail electricity price series was as follows. Retail revenue and sales by utility are obtained from individual utility monthly Financial and Operating (F&O) Reports submitted to BPA. The data are summed to obtain the total GPU level and then the total monthly sales revenue is divided by total regional monthly kWh sales. The quotient equals the monthly average regional retail electricity price. These data are converted to real 1994 mills per kWh by using the current implicit GNP deflator used in BPA's Supply Pricing Model (SPM). The resultant series is used in estimating the monthly electricity load model. (Pend Oreille County PUD F&O data are insufficient over the model estimation period, therefore these data are excluded in the calculation of historical average GPU retail price. However, due to the relatively small proportion that Pend Oreille County PUD's load contributes to total GPU load, it is expected that the exclusion of this data has little effect on the determination of average retail electricity price.)

3.9.2.2 Forecast The retail electricity price forecast is developed using BPA's SPM. A discussion of the SPM is provided in section 3.19 of this document.

Section 3.10 contains the historical nominal retail electricity price series and the nominal and real forecasted retail electricity price series. The deflator used to convert nominal historical prices to real prices is implied in the real/nominal relationship in the forecast file.

3.9.3 Weather Inputs

3.9.3.1 Historical The historical degree-day data are derived from daily temperature data as reported by eight National Oceanic and Atmospheric Administration (NOAA) stations located throughout the region. The stations are Eugene, Ephrata, Everett, Longview, Newport (WA), Puyallup, Seattle, and Wenatchee. The station-level degree-day data are weighted by the share of load (in 1987) adjacent to that station. Heating degree-day weights are based on residential and commercial loads, while cooling degree-day weights are based on residential, commercial, and irrigation loads. The station-level degree-day data are contained in section 3.11 of this document.

3.9.3.2 Forecast The forecasts of the weather inputs (heating and cooling degree-days) are based on 39 years of daily temperature data for each of the eight stations in the GPU combined service territory. The degree-day data are created as follows. For each of the eight stations, average daily minimum and maximum temperatures for each day of the year are calculated for the period 1950 through 1988 (i.e., n=39 for each day of the year). Given the minimum and maximum averages, heating and cooling degree-day data for each station are calculated for each day. Monthly average degree-day data for each station are calculated. The station-level data are then weighted by the share of load adjacent to each of the weather stations. Heating degree-day weights are based on residential and commercial loads, while cooling degree-day weights are based on residential, commercial, and irrigation loads.

3.9.4 Economic Inputs

3.9.4.1 Historical The variable selected to capture the economy's effect on total demand for electricity for the GPUs is total nonagricultural employment for the state of Washington and Lane County, Oregon. See section 3.2.4 for a description of the source for historical employment data for the state of Washington. Lane County monthly historical employment data are obtained from the Employment Department, state of Oregon. The monthly data for the state of Washington and Lane County, Oregon, are summed to create the employment variable used to develop the GPU model. See section 3.5 of this document.

3.9.4.2 Forecast Projections of total nonagricultural employment for the state of Washington are derived using BPA's Regional Economic Forecasting Model (REM). See section 2.1 for details pertaining to the REM. Projections of monthly employment for Lane County, Oregon, are derived from BPA’s county-level economic forecasts. The total nonagricultural employment variable used in the forecast process is created by summing the state of Washington and Lane County, Oregon, projections. See section 3.5 of this document.

3.9.5 Load Inputs The historical monthly load data used in modeling total GPU loads was extracted from two sources: Northwest Power Pool (NWPP) data and BPA's Automated Energy Statistical Sales System (AESSS) database. NWPP data are used for Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, Seattle City Light, and Tacoma Public Utilities. AESSS data are used for Cowlitz County PUD, Snohomish County PUD, and Pend Oreille County PUD because they are not members of NWPP, and therefore do not report their loads to the NWPP. (For a description of the AESSS database and the adjustment to convert the data from billing to calendar month, see section 3.2.5.)

The utility-specific data are summed to obtain total GPU load. The total GPU load is reduced by 180 aMW to remove the load for Colockum Transmission Co. The Colockum load is accounted for separately in BPA load/resource studies (180 aMW for energy and 183 MW for peak). The data include utility distribution losses but exclude Federal transmission losses.

The regional GPU historical loads also are adjusted to account for conservation savings attributed to BPA's conservation programs. The monthly historical GPU loads are increased by about 80 percent of the amount of conservation that has been estimated to have occurred as determined by BPA's Conservation and Energy Services Group. If the effects of programmatic conservation were not removed, the retail electricity price coefficient estimated in the model would be overstated: retail electricity prices rose during the same time period (early to mid-1980s) that significant conservation efforts began. The remaining 20 percent of conservation estimates are considered to be price-induced and are not included in the conservation adjustment to historical loads. Retail electricity price effects are assumed to be captured in the retail electricity price coefficient included in the model. See section 3.23 of this document.

The adjusted historical monthly load series for the period January 1981 through June 1994 was used to develop the forecast of total GPU loads used in this rate filing. See section 3.12 of this document.

3.9.6 Dummy Variables Over the estimation period, certain months were consistently over- or under-forecasted. To more accurately reflect the monthly shaping, dummy variables were introduced. These variables had the effect of reapportioning the loads between the months without affecting the annual load levels.

3.9.7 Model Estimation As illustrated in Chart 3, after the historical input data are obtained, the next stage in developing a forecast is to estimate the model. Given the theoretical form described previously, the historical relationships between the demand for electricity and weather, employment, and retail electricity price are statistically determined.

The model estimation is conducted using the Statistical Analysis System (SAS) software package developed by the SAS Institute, Inc. The SAS code for the GPU forecast model is in section 3.13 of this document.

The model represents a demand equation given the following criteria: (1) theoretical structure; (2) availability and reliability of data (historical and forecasted); (3) appropriate signs and reasonable magnitude of the equation's coefficients; (4) statistical significance of the variables (t-statistics); (5) overall statistical fit of the model to the historical data (R-square); and (6) comparison of the actual and fitted values (Mean Square Error).

The model specification selected to forecast GPU loads is identified in Table 15. Definitions of the variables used in the model are listed in Table 16. Tables 17 and 18 present the mean error and percent difference (net and absolute) between the actual and estimated values over the model estimation period, January 1981 through June 1994.

Once the model is estimated, the next stage in the total GPU load forecasting process is to forecast the independent variables (retail electricity price, employment, and weather). Given these inputs, the estimated model is used to generate a regional forecast of GPU loads.

3.9.8 Energy Load Forecast In the final stage of the load forecast process, the forecasted independent variables are used in the estimated model to produce a forecast of GPU loads. These projected loads are then reduced by: (1) estimated future savings resulting from BPA conservation programs and (2) estimated future savings due to additional conservation, conservation reinvention, and customer-funded conservation. (See section 3.21 of this document.) Additions were also made to the total GPU load forecast to reflect expected increases in industrial activity not captured in the estimation period.

The GPU load forecasting model predicted loads through September 2003. The forecast was extended through September 2005 using year-to-year growth rates averaged by month over the last two years of the forecast.

After implementing the above adjustments, the forecast represents a projection of loads that have to be met by generating resources (refer to Chart 4) and/or by purchases of non-BPA power (see section 3.15 of this document). The final total GPU forecast is in Appendix 1 of this document.

3.9.9 Peak Load Forecast A noncoincidental peak load forecast is used for revenue projections and capacity rate determinations. The monthly GPU peak forecast is derived from load factors (by year and month), as calculated from the total of the utilities' own forecasts submitted to the PNUCC (NRF, March 1994), applied to the energy forecast. The final peak load forecast is provided in Appendix 1 of this document.

3.9.10 Disaggregation The GPU forecast is disaggregated to obtain utility-specific forecasts for use in computing load/resource balances and calculating low density discounts. This procedure entails developing ratios representing each utility's share of monthly total GPU loads (peak and energy) based on the GPU submittals to the PNUCC (March 1994) and BPA's analyses regarding current and expected load trends for each utility. The individual utility load forecasts produced by the disaggregation process are contained in section 3.14 of this document.

3.15 Adjustments to Public Utility Purchases from BPA

To account for the competitive forces of the deregulated electricity market, BPA made adjustments to its forecasts of NSGPU and GPU purchases from BPA. Table 19 details these adjustments which range from 209 aMWs in OYs 1997 and 1998, to 368 aMWs in OY 2000 and beyond.

3.15.1 Description of the Adjustment Process Given the deregulation of the electricity market, Pacific Northwest utilities are being presented with offers from numerous suppliers entering into the wholesale electricity market. BPA believes some of its utility customers will leave the federal system, either totally or in part, and purchase power from alternative suppliers. BPA may not know at this time which utilities will, in fact, leave the federal system, but BPA does know which utilities have been actively seeking alternative power suppliers through the information contained in utilities' Firm Resource Exhibit (FRE) submittals. The load amounts reflected in the utility FRE submittals to BPA before February 1, 1995, were the basis for the adjustments to public utility purchases from BPA (utilities' total system loads minus dedicated resources). Additional adjustments beyond utilities' FRE submittals are made to the forecast of NSGPU and GPU purchases from BPA to reflect the desire of some utilities to diversify their resource bases beyond the pre-February 1, 1995 FRE submittals. This adjustment is based on evidence other than the FREs submitted prior to February 1, 1995 (e.g., Pacific Northwest Generating Company's request for proposals on behalf of its utility members, new utility FRE submittals after February 1, 1995, etc.). It is estimated that the NSGPUs could diversify roughly 600 aMW of load, but it is assumed that two-thirds of that amount could be successfully competed for and served by BPA contracts. It is assumed that the remaining third of the NSGPU diversification amount would be covered by alternative suppliers by OY 1999.

For the GPUs, it is estimated that an average of 10 percent of purchases from BPA (utility total system load minus dedicated resources) is at risk of being served by alternative suppliers by OY 1997. BPA assumes that GPU customers will purchase power under the existing 1981 Contracts. BPA believes that its forecast of GPU purchases from BPA will adequately reflect the potential load reduction that could occur by these utilities within their rights under the 1981 Contract, given current market information. Because the load commitment negotiations were not at a definitive stage when the load forecast for this study was completed, BPA is not basing the final load and resource study on the outcome of those negotiations.

3.16 Forecasts of Unbundled Products Purchases by Public Utilities and Federal Agencies

Table 20 contains the forecast of unbundled product purchases by the public utilities and Federal agencies. Following are explanations of how the forecast of utility purchases of each unbundled product was derived. Refer to the WPRDS, WP-96-FS-BPA-05A, for definitions and pricing information for BPA's unbundled products.

3.16.1 Load Shaping All NSGPUs are forecasted to purchase full load shaping from BPA. Some NSGPUs are assumed to receive industrial exemptions totaling roughly 150 aMW. The estimate of possible industrial exemption load is based on information on industrial plant load in NSGPU service territories that is greater than 5 aMW per year. It is assumed that one-third of the industrial load greater than 5 aMW is comprised of "predictable" loads, and therefore would qualify for industrial exemptions. NSGPU system loads minus the qualifying industrial exemption load were used as the basis for the NSGPU load shaping forecast.

Most Actual Computed Requirement GPU customers purchasing PF power are forecasted to purchase full load shaping with an industrial exemption option. The load shaping forecast is based on the assumption that the GPU customers will purchase power under the 1981 Contracts instead of the 1996 Contract. Under the 1981 Contract, Actual Computed Requirements GPU customers must purchase the load shaping product, while it is an option under the 1996 Contract. The estimate of the total possible industrial exemption load is based on the amount of a GPU's industrial load using greater than 5 aMW per year of electricity. The industrial load with aMW usage greater than 5 aMW for Cowlitz Co. PUD is estimated to be about 400 aMW, 60 aMW for Pend Oreille Co. PUD and 100 aMW for Snohomish Co. PUD. It is assumed that Snohomish Co. PUD will have 75 aMW of qualifying industrial exemption load, Cowlitz Co. PUD will have 200 aMW, and Pend Oreille Co. PUD is not assumed to have any load qualifying for the industrial exemption. GPU system loads minus the qualifying industrial exemption loads were used as the basis for the GPU load shaping forecast. Chelan Co. PUD, Douglas Co. PUD, and Tacoma City Light are assumed not to purchase load shaping products from BPA. Although Chelan and Douglas are Actual Computed Requirements customers, they are forecasted not to buy load shaping because they are forecast not to take deliveries under their 1981 Contract.

It was assumed that the Federal agencies will purchase load shaping for all of their load.

Table 20 shows the forecast of the unbundled product purchases by the NSGPUs, GPUs, and Federal agencies.

TABLE 20

FORECASTS OF UNBUNDLED PRODUCTS PURCHASES BY PUBLIC UTILITIES AND FEDERAL AGENCIES

Fiscal Year	Full Load Shaping (aMWs)	Partial Load Shaping (aMWs)	Load Regulation (aMWs)	Control Area Reserves (aMWs)
1997	5755	0	4631	572
1998	5774	0	4680	572
1999	5715	0	4728	573
2000	5765	0	4757	573
2001	5798	0	4788	573

3.16.2 Load Regulation All NSGPUs and GPUs in BPA's control area or served by other utilities for BPA through transfer agreements are assumed to receive Load Regulation from BPA. Utility system loads from the 1996 final Loads and Resources Study are used as the forecast of the quantity of the load regulation product that will be purchased. (see Documentation, Volume 2, WP-96-FS-BPA-01B, TableS U-8 through U-22) Eugene Water and Electric Board is forecasted to stay within BPA's control area but is assumed to provide its own load regulation. Utilities not in BPA's control area and that are not served by other utilities for BPA through transfer agreements include Seattle City Light, Tacoma City Light, Chelan Co. PUD No. 1, Douglas Co. PUD No. 1, Grant Co. PUD No. 2 and Clark Co. PUD. These utilities are assumed not to receive load regulation from BPA. The forecast of purchases of the load regulation product for nonfederal load for FY 1997-FY 2001 is contained in Table 20.

3.16.3 Control Area Reserves for Resources Those utilities which operate firm hydro or thermal resources located in BPA's automatic generation control area, or which purchase non-utility generation located in BPA's automatic generation control area are forecasted to purchase this product. For the NSGPUs, the aMW amount of their hydro and thermal resources was used as the quantity of reserves purchased (see Documentation, Volume 2, WP-96-FS-BPA-01B, Table U-17). For the GPUs, historical operating reserve requirements were used as quantity of reserves purchased. Eugene Water and Electric Board was assumed to purchase only half of its operating reserves from BPA since they are planning to provide a portion of their own operating reserves. The forecast of purchases of the control area reserves for resources product for FY 1997-FY 2001 is contained in Table 20.

3.17 Forecasts of Unbundled Products Purchases by DSIs

Table 21 contains the forecast for the unbundled product purchases by the DSIs. Following are explanations of how the forecast of DSI purchases of each unbundled product was derived. Refer to the WPRDS, WP-96-FS-BPA-05A, for definitions and pricing information on BPA's unbundled products.

3.17.1 Load Shaping. Based on a combination of signed contracts and anticipated contracts for the five-year IP block sale, BPA projects few DSIs will purchase the DSI load shaping product for increases and decreases relating to their plant operations.

3.17.2 Load Regulation All DSIs are assumed to purchase the load regulation product to supplement their federal loads. The forecast of DSI purchases of the load regulation product is directly related to the aluminum and nonaluminum DSI loads served by BPA. See sections 3.1.1 and 3.1.2 of this document for the forecasts of aluminum and nonaluminum DSI loads served by BPA.

3.17.3 Shaping Services It is assumed that the DSIs will purchase shaping services to supplement their non-federal power purchases. It is assumed that the aluminum and nonaluminum DSIs who are expected to purchase non-federal power will require the flexibility to use the power on a schedule different from how the seller provides it, therefore requiring the purchase of BPA's shaping service product. The assumption was that these purchases could deviate by about 5%, and DSIs would want BPA to cover for this deviation through their "load factoring product." The forecast of DSI purchases of the shaping service product is five percent of the amount of DSI load projected to be purchased from alternative suppliers. See sections

3.1.1 and 3.1.2 of this document for projections of DSI loads to be purchased from alternative suppliers.

TABLE 21

FORECASTS OF UNBUNDLED PRODUCTS PURCHASES BY DSIs

	Load Shaping aMW	Load Regulation aMW	Control Area Reserves aMW	Shaping Services aMW
FY 1997	140	1842	0	67
FY 1998	140	1842	0	67
FY 1999	140	1842	0	67
FY 2000	140	1842	0	67
FY 2001	140	1842	0	67

3.18 Public Utility and DSI Loads at Current Rates

Table 22 below shows the forecasts of public utility and DSI loads at current BPA rates, if the proposed rates were not adopted.

TABLE 22
PUBLIC UTILITY AND DSI LOADS AT CURRENT RATES
(aMW PURCHASES FROM BPA)

Operating Year	1997	1998	1999	2000	2001
Public utilities					
Current rate	3004	2710	2626	2717	2877
Proposed rate	4422	4300	4420	4533	4760
DSIs					
Current rate	39	39	39	39	39
Proposed rate	1875	1842	1842	1842	1842

The projections of BPA sales to public utility customers were based on information on the market price for power, the customer actions to seek alternative power supplies at lower prices, and customer actions to diversify their resource portfolio at any cost. Examples of consummated and potential deals between BPA's customers and other suppliers are described in the testimony of Moorman and Evans, WP-96-E-BPA-65.

The projections of BPA sales to DSI customers were based on the analysis of the underlying economics of each DSI customer and their respective utilization and costs of power, together with knowledge of actions being taken by DSI customers to enter into power contracts with other suppliers.

3.19 Supply Pricing Model

BPA's Supply Pricing Model (SPM) was used to develop the retail electricity price projections for the NSGPU and GPU load forecasts. The SPM simulates BPA's rate-setting process by projecting wholesale electricity rates and then combining utility purchases from BPA with utility costs to project retail electricity prices. The SPM processes data and performs calculations on an annual basis. In order to develop retail electricity prices on a monthly basis, assumptions are made about the monthly variations in these rates. For the NSGPUs and GPUs, distribution costs are escalated on a monthly basis. It is also assumed that the NSGPUs and GPUs begin increasing their retail rates 6 months prior to an anticipated BPA wholesale rate increase until the full effect is incorporated in the month of the BPA rate increase. For a more complete description of the SPM, see Documentation for Section 7(b)(2) Rate Test Study, WP-96-FS-BPA-07A.

3.20 Investor-Owned Utility Forecast

A forecast of total system loads for the investor-owned utilities (IOU) is used for hydro-regulation studies (as a component of total regional loads). The six IOUs in the region are: Idaho Power Company, Montana Power Company, Pacificorp, Portland General Electric Company, Puget Sound Power and Light Company, and Washington Water Power Company.

The total IOU load forecast used in this final rate filing updates the economic assumptions from the April 1991 joint BPA/NPPC long-term forecast, and it also utilizes a modified version of the residential sector model. For documentation concerning the April 1991 joint BPA/NPPC forecast, see 1991 Northwest Conservation and Electric Power Plan, Volume II, Part 1, May 1991.

To produce utility-specific forecasts, the total IOU load forecast is disaggregated by year and month based upon the utilities' forecast submittals to the PNUCC for use in the Northwest Regional Forecast of Power Loads and Resources (March 1994).

The total IOU load forecast reflects the estimated savings resulting from regional adoption of Model Conservation Standards (MCS). The total IOU load forecast is contained in Appendix 1 of this document.

3.21 Conservation Savings

The 1996 final rate filing load forecast includes as load reductions current and planned future BPA conservation program savings and savings resulting from additional conservation, conservation reinvention, and customer-funded conservation.

The conservation load reductions were made in the load forecasting process. No further conservation reductions were made to the public utility loads in the loads and resources analysis.

The conservation savings are detailed in Table 1 of the Loads and Resources Study, WP-96-FS-BPA-01.

3.24 Contract Federal Agencies

The peak and energy forecasts for the contract federal agencies are developed by staff in BPA field offices in cooperation with each agency. They are reviewed periodically and updated as needed. The customers classified as contract federal agencies are: U.S. Bureau of Mines (Albany, OR), Fairchild Air Force Base (Galena, WA), Department of Energy (Richland, WA), U.S. Bureau of Indian Affairs (Wapato, WA and Polson, MT), and the U.S. Department of the Navy (Bremerton, Bangor, and Arlington, WA). The load forecast for the contract federal agencies is part of the base case forecast in Appendix 1 of this document.

3.25 U.S. Bureau of Reclamation (USBR)

Hydro projects, owned and operated by the USBR as part of the federal system, were constructed to serve irrigation needs in addition to producing electric power and aiding in flood control. The USBR is entitled to "reserve" adequate power from its projects to ensure that irrigation needs are met. This "reserved energy" is included in the forecast of electric energy use in the PNW region. BPA wheels this energy for the USBR and is reimbursed for the service. The peak and energy forecasts of the reserved energy at each project are reviewed and updated periodically by the USBR at the request of BPA. The USBR load forecast is part of the base case load forecast in Appendix 1 of this document.

3.26 Residential Purchase and Sale Agreement (RPSA) and Exchange Transmission Credit Agreement (ETCA)

Pursuant to section 5(c)(1) of the Northwest Power Act, BPA entered into Residential Purchase and Sale Agreements (RPSA) and Exchange Transmission Credit Agreements (ETCA) with regional utilities. See Table 23 for a list of utilities participating in each program. Because the costs of these programs are to be recovered through BPA revenues, it is necessary to develop forecasts of the loads of each participating utility.

The residential exchange load forecasts for the investor-owned utilities are provided by each utility. BPA's IOU residential exchange forecast reflects information provided by the IOUs as of second quarter of calendar year 1995.

Residential exchange load forecasts for the NSGPU customer group are developed in the following manner. First, individual system load forecasts for each NSGPU are developed by disaggregating the NSGPU customer group total system load forecasts as described in section 3.2.10 of this document. Next, exchange-eligible forecasts are developed by applying monthly residential, small farm, and irrigation factors to the utility-level total system load forecasts. These monthly factors are based upon the portion of each utility's total system load that was eligible for exchange in 1987.

The residential exchange forecasts reflect the loads of the eligible consuming sectors (residential, small farm, and irrigation) as defined by the exhibits to the contracts. Included in these forecasts are monthly estimates of peak and energy loads and monthly distribution losses that are associated with the exchange-eligible portion of system load. The residential exchange forecasts are presented in section 3.27 of this document.