Administrator's Record of Decision

1987 Final Rate Proposal

BPA

U.S. Department of Energy
Bonneville Power Administration

DOE/BP-849
July 1987

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1987 WHOLESALE POWER AND TRANSMISSION RATE PROPOSAL

ADMINISTRATOR'S RECORD OF DECISION

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

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1987 wholesale power and transmission rate proposal : administrator's record of
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RECORD OF DECISION

TABLE OF CONTENTS

		Page
COMMONLY USED ACRONYMS		iv
I.	INTRODUCTION	1
	A. Procedural History of the Rate Proceeding	1
	B. Legal Guidelines Governing Establishment of Rates	3
	1. Statutory Guidelines	3
	2. The Broad Ratemaking Discretion Vested in the Administrator	4
	C. Confirmation and Approval of Rates	5
II.	PRELIMINARY ISSUES	7
	A. Introduction	7
	B. Key Commodity Prices	7
	1. Aluminum Prices	7
	2. Fossil Fuel Prices	8
	C. Forecasted Aluminum DSI Loads	11
	D. Forecasted Surplus Power Sales	13
	E. Price Elasticity	14
III.	RISK MANAGEMENT	21
	A. Introduction	21
	B. Risk Assessment Analysis	23
	1. Introduction	23
	2. Methodology	23
	3. Determination of Revenue Risks	26
	4. Assignment of Probabilities to Risk Components	27
	5. Results of the Risk Assessment Analysis	29
	C. Risk Management Strategy	31
	1. Introduction	31
	2. Level of Risk Coverage	33
	3. Selection of Risk Mitigation Measures	35
	D. Use of 1939 Water Conditions	38
	E. Investment Service Coverage	41
	F. Cost Recovery Adjustment Clause (CRAC)	51
IV.	REVENUE REQUIREMENT	73
	A. Introduction	73
	B. Segmentation	74
	C. Repayment Studies	75
	D. Revenue Requirement Study	79

		Page
V.	MARGINAL COST ANALYSIS	87
	A. Introduction	87
	B. Classification of Capacity and Energy Costs	87
	C. Seasonalization of Capacity and Conservation Costs	94
VI.	SECTION 7(b)(2) RATE TEST	99
VII.	COST ALLOCATION	117
	A. Seasonalization of Energy Costs	117
	B. Section 7(b)(2) Industrial Adjustment	118
	C. Rate Design Sequencing	121
	D. DSI Floor Rate	124
	E. WNP-1 Exchange	135
	F. Section 7(b)(3)	137
VIII.	RATES FOR NONFIRM ENERGY	143
	A. Introduction	143
	B. NF-87 Rate	143
	1. Nonfirm Energy Cost Determination and Recovery	143
	a. Legal Considerations	146
	b. Should Exchange Costs Be Allocated to Nonfirm Energy Rates	148
	2. Nonfirm Energy Rate Design	158
	3. Share-the-Savings Rate	169
	4. Energy Broker Rate (EB-87)	171
	C. Nonfirm Energy Rate Cap	171
	D. Marketing Linear Programming and Nonfirm Revenue Analysis Program	187
IX.	WHOLESALE POWER RATES	193
	A. General Rate Design Issues	193
	1. Irrigation Discount	193
	2. Low Density Discount	203
	3. Availability Charge	205
	4. Unauthorized Increase Charge	206
	B. Priority Firm Power Rate (PF-87)	207
	C. Industrial Firm Power (IP-87) and Variable Industrial (VI-87) Rates	210
	D. Firm Capacity Rate (CF-87)	210
	E. New Resources Firm Power Rate (NR-87)	211
	F. Surplus Firm Power Rates	213
	1. Long-Term Surplus Firm Power Rate (SL-87)	213
	2. Short-Term Surplus Firm Power Rates (SP-87)	223

Page

X. TRANSMISSION RATES 229

A. Introduction 229
B. Southern Intertie Nonfirm Transmission Rate (IS-87A) 229
C. Southern Intertie Firm Power Transmission Rate (IS-87B) . . . 238
D. Northern Intertie Rate (IN-87) 241
E. Market Transmission Rate (MT-87) 242
F. Lost Opportunity Rate (IS-87B2) 251
G. Other Transmission Rate Issues 253

XI. ENVIRONMENTAL ASSESSMENT 255

XII. COMMENTS OF PARTICIPANTS 265

XIII. CONCLUSION 273

APPENDICES

A LIST OF PARTIES AND ABBREVIATIONS A1

B 1987 WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS B1

C 1987 TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS C1

COMMONLY USED ACRONYMS

AC - Alternating Current
AFUDC - Allowance for Funds Used During Construction
ASC - Average System Cost
ASM - Aluminum Smelter Model
BPA - Bonneville Power Administration
BTU - British Thermal Unit
CARP - Coordination Agreement Reserve Program (computer program)
CEM - Computed Energy Maximum
CF - Firm Capacity (rate)
COSA - Cost of Service Analysis
CRAC - Cost Recovery Adjustment Clause
CSPE - Columbia Storage Power Exchange
CT - Combustion Turbine
CWIP - Construction Work in Progress
DC - Direct Current
DOE - Department of Energy
DSIs - Direct Service Industrial Customers
DSM - Demand-Side Management
EA - Environmental Assessment
EAC - Exchange Adjustment Clause
EB - Energy Broker (rate)
ECC - Energy Content Curve
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
FD - Firm Displacement Power (rate)
FELCC - Firm Energy Load Carrying Capability
FERC - Federal Energy Regulatory Commission
FPC - Federal Power Commission (now FERC)
FPT - Formula Power Transmission (rate)
FY - Fiscal Year
GCPs - General Contract Provisions
GRSPs - General Rate Schedule Provisions
GTRSPs - General Transmission Rate Schedule Provisions
HCD - High Cost Displacement
IE - Eastern Intertie
IN - Northern Intertie
IOUs - Investor-Owned Utilities
IP - Industrial Firm Power
IR - Integration of Resources (rate)
IRE - Interruptible Replacement Energy
IS - Southern Intertie
ISC - Investment Services Coverage
kV - Kilovolt (1000 volts)
kW - Kilowatt (1000 watts)
kWh - Kilowatthour
LCMM - Least Cost Mix Model
LDD - Low Density Discount
LOLP - Loss of Load Probability
LTIAP - Long-Term Intertie Access Policy

MCA - Marginal Cost Analysis
ME - Measured Energy
MW - Megawatt (1 million watts)
MW-miles - Megawatt-miles
NEPA - National Environmental Policy Act
NF - Nonfirm Energy (rate)
NFRAP - Nonfirm Revenue Analysis Program
NR - New Resource Firm Power
NTIAP - Near-Term Intertie Access Policy
O&M - Operation and Maintenance
OY - Operating Year
PF - Priority Firm Power (rate)
PNUCC - Pacific Northwest Utilities Conference Committee
PNW - Pacific Northwest
PSW - Pacific Southwest
PURPA - Public Utilities Regulatory Policies Act
PUD - Public or Peoples' Utility District
RAM - Rate Analysis Model (computer program)
RDS - Rate Design Study
REVEST - Revenue Estimate (computer program)
ROD - Record of Decision
SAM - System Analysis Model
SCADA - Supervisory Control and Data Acquisition
SE - Surplus Firm Energy (rate)
SI - Special Industrial (rate)
SP - Surplus Firm Power (rate)
SPC - Sustained Peaking Capacity
SPM - Supply Pricing Model (computer model)
SS - Share-the-Savings (nonfirm energy rate)
TC - Telecommunication
TGT - Townsend-Garrison Transmission (rate)
TRDS - Transmission Rate Design Study
UFT - Use of Facilities (rate)
VOR - Value of Reserves
WNP - Washington Public Power Supply System (Nuclear) Project
WPPSS - Washington Public Power Supply System
WPRDS - Wholesale Power Rate Design Study
WSPP - Westerm System Power Pool
WSCC - Western Systems Coordinating Council

CHAPTER I

INTRODUCTION

A. Procedural History of the Rate Proceeding

On November 7, 1986, BPA published notices of intent to revise its wholesale power and transmission rates. 51 FR 40,484 and 40,483 (1986). Subsequently, BPA published initial proposals for revised and new rates on December 30, 1986, 51 FR 47,108 and 47,144 (1986), together with notice of the date, time and location at which a prehearing conference would be held. The proposed effective date for the new rates is October 1, 1987, subject to interim approval of the Federal Energy Regulatory Commission (FERC). 16 U.S.C. §839e(a)(2).

In accordance with section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. §839(e)(i), evidentiary hearings on the proposed rate adjustments were conducted by Judge Dean F. Ratzman and Judge William J. Sweeney, Hearing Officers. Forty-five interventions were filed by publicly owned and investor-owned utility customers, direct-service industrial customers, State agencies, Federal agencies, and public interest groups. Judges Ratzman and Sweeney commenced the hearings with a prehearing conference on January 16, 1987, which took up issues of interventions and scheduling. On that date the hearing officers issued their rules of practice and procedure, entitled Special Rules Of Practice To Govern This Proceedings.

BPA's direct testimony and technical studies, sponsored by 27 witnesses, were prefiled on January 16. The parties filed their initial direct testimony and answering case on issues concerning surplus firm power rates, nonfirm energy rates, and irrigation discount rates on March 2, 1987. BPA filed supplemental direct testimony on March 2, 1987. The parties filed the balance of their direct testimony on March 10, 1987. BPA and the parties filed rebuttal testimony on March 30 and surrebuttal testimony on April 6, 1987. Motions to strike BPA's prefiled testimony and parties' prefiled testimony were made and ruled upon in March and April 1987.

During the course of discovery, BPA responded to 565 data requests concerning all aspects of its initial and revised proposals. Twelve days of transcribed oral discovery sessions comprising some 1,486 pages were conducted between January 26 and April 2 on all prefiled testimony.

Cross-examination began on April 7, 1987, and extended through April 22, 1987. Concurrent sessions of cross-examination were conducted by Judge Dean F. Ratzman and Judge William J. Sweeney, who ruled on all motions and related procedural matters raised during this period. There were a total of 17 days of cross-examination, of which 7 days contained concurrent sessions before both hearing officers, comprising a total of 1,746 transcribed pages.

Initial legal briefs were filed by 20 parties on May 15, 1987.

Parties presented oral arguments on May 21 and 22 before a BPA panel comprised of James Jura, Administrator; Robert Ratcliffe, Deputy Administrator; Steven Hickok, Executive Assistant Administrator; Edward Sienkiewicz, Assistant Administrator for Power and Resources Management; Stephen Ailshie, Assistant Administrator for Financial Management; and Harvard Spigal, Esq., General Counsel.

Persons interested in commenting on BPA's proposed rates, but who did not wish to become parties to the formal evidentiary hearings, had the opportunity to provide written or oral comments. BPA conducted a series of eight transcribed field hearings during February 1987: Spokane, Tacoma, Everett, and Richland, Washington; Portland and Eugene, Oregon; Burley, Idaho; and Jackson, Wyoming. A public comment forum was held on April 30, 1987, in Portland, Oregon. BPA has also received and considered 7,541 written comments. The transcribed field hearings and the written comments became part of the record on which the Administrator based his decisions.

On June 15, 1987, BPA issued its Draft Record of Decision. This document presented the Administrator's draft decisions on issues raised in the rate proceeding, based on his review of evidence, oral argument, initial briefs, and written comments. However, those decisions were not final in either the legal or practical sense. The Administrator has reconsidered his decisions based on the parties' briefs on exceptions, filed June 29, 1987.

BPA issues this Record of Decision on July 31, 1987. This document contains the BPA Administrator's final rate determinations, based on his review of the record compiled in this proceeding. This Record of Decision does not, however, include discussion of proposed program spending levels. BPA reviewed program cost levels for the fiscal year 1988 and 1989 budgets in a separate public process that preceded the rate case. The Administrator does not reexamine program level decisions in the rate case. 51 FR 47,108 (1986).

The Record of Decision is divided into thirteen chapters. The first ten chapters are primarily concerned with issues raised by parties to the evidentiary proceeding. Issues of a technical nature raised by "participants" (commenters who did not become formal parties) are also discussed in these chapters. Participant comments of a general nature are discussed in Chapter XII.

Each chapter corresponds to a particular area of the rate case. This chapter, Chapter I, discusses the procedural history of the case, legal guidelines governing the establishment of rates, and review and approval of BPA's rates. Chapter II discusses preliminary issues such as load forecasts and surplus power sales assumptions, which affect later ratemaking steps. Chapter III concerns BPA's risk management strategy, designed to assure that BPA meets its repayment obligation to the U.S. Treasury.

Chapter IV discusses determination of BPA's revenue requirement. Chapter V concerns BPA's marginal cost analysis, which is used to determine the classification of costs between demand and energy and the time-differentiation of costs and rates. Chapter VI discusses BPA's rate determination made pursuant to section 7(b)(2) of the Northwest Power Act. Chapter VII concerns cost allocation. Chapter VIII discusses BPA's rates for sales of nonfirm energy. Chapter IX discusses the design of BPA's other power rates. Chapter X is devoted to transmission rates. Chapter XI discusses issues related to potential environmental consequences of BPA's rates. Chapter XII concerns the comments of participants. Chapter XIII presents the Administrator's conclusions regarding the final rate proposal.

Individual issues within any given chapter are discussed in three steps. First, the issue is stated. Second, the positions of BPA and the parties are evaluated. Third, the Administrator's decision is stated.

This Record of Decision contains several appendices. Appendix A is a list of parties to the formal hearing. Appendix B contains BPA's final power rate schedules and the General Rate Schedule Provisions associated with these rates. Appendix C contains BPA's final transmission rate schedules and the associated General Transmission Rate Schedule Provisions.

B. Legal Guidelines Governing Establishment Of Rates

1. Statutory Guidelines

Section 6 of the Bonneville Project Act, 16 U.S.C. §832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers to become effective upon confirmation and approval by the Federal Power Commission (which has been succeeded by FERC). This section directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the Bonneville Project Act, 16 U.S.C. §832f, provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the capital investment over a reasonable period of years.

The Federal Columbia River Transmission System Act (Transmission Act), 16 U.S.C. §838, contains requirements similar to those of the Bonneville Project Act. Section 9 of the Act, 16 U.S.C. §838g, provides three guidelines for the establishment of rates: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including the amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels which produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses,

and interest in connection with bonds issued under the Transmission Act. Section 10 of the Transmission Act, 16 U.S.C. §838h, allows for uniform rates, and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

The Flood Control Act of 1944 contains ratemaking requirements similar to the Bonneville Project Act and the Transmission Act. Section 5 of the Flood Control Act directs that rate schedules encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. §825s. Section 5 also provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting such electric energy, including the amortization of the Federal investment over a reasonable number of years.

In addition to the Bonneville Project Act, the Transmission Act, and the Flood Control Act of 1944, the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) provides numerous rate directives. Section 7 directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Rates are to be set to recover, over a reasonable period of years, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be repaid by power revenues). 16 U.S.C. §839e(a)(1). Section 7 also contains rate directives describing how rates for individual customer groups may be derived.

Section 7 also provides procedural guidelines to be used when developing rates, including publication of notice in the Federal Register of the proposed rates, a hearing before a hearing officer, an opportunity to submit oral and written comment, and an opportunity to refute or rebut other material submitted in the record. 16 U.S.C. 839e(i). BPA has expanded on these statutory directives by promulgating rules of agency procedure to aid in the conduct of these hearings. 51 FR 7611 (1986).

2. The Broad Ratemaking Discretion Vested In The Administrator

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. See Pacific Power & Light v. Duncan, 499 F. Supp 672 (1980); Accord City of Santa Clara v. Andrus, 572 F.2d 660, 668 (9th Cir. 1978) ("widest possible use" standard is so broad as to permit "the exercise of the widest administrative discretion"); ElectriCities of North Carolina v. Southeastern Power Administration, 774 F. 2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit has also recognized the Administrator's ratemaking discretion. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (Upheld BPA on the merits of every rate issue and stated "[b]ecause BPA helped draft and must administer the Act, we give substantial deference to BPA's statutory interpretation."); Pacificorp v. FERC, 795 F.2d 816, 821 (9th Cir. 1986) ("BPA's interpretation is entitled to great deference and must be upheld unless it is unreasonable."); Atlantic Richfield Co. v. Bonneville Power Administration, Nos. 83-7971, 83-7981, 85-7473, and 85-7488 (9th Cir. June 5, 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities"); Cf. Aluminum Company of America v. Central Lincoln Peoples' Utility District, 467 U.S. 380, 389 (1984) ("The Administrator's interpretation of the Regional Act is to be given great weight."); Department of Water and Power of the City of Los Angeles v. BPA, 759 F.2d 684, 690 (9th Cir. 1985) ("Insofar as agency action is the result of its interpretation of its organic statutes, the agency's interpretation is to be given great weight.").

C. Confirmation And Approval of Rates

BPA's rates become effective upon confirmation and approval by FERC. 16 U.S.C. §§839e(a)(2) and (k). FERC's review is appellate in nature, based on the record developed by the Administrator. U.S. Department of Energy, Bonneville Power Administration, 13 FERC ¶61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator, but may only confirm, reject or remand them. U.S. Department of Energy, Bonneville Power Administration, 23 FERC ¶61,378, 61,801 (1983).

With respect to rates for sale within the Pacific Northwest region, the Commission determines whether (1) rates are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting BPA's other costs; (2) rates are based on BPA's total system costs, and (3) transmission rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. United States Department of Energy - Bonneville Power Administration, 39 FERC ¶ 61,078, 61,206, (1987). The limited FERC review of regional rates permits the Administrator substantial discretion in the design of rates and the allocation of costs, neither of which are subject to FERC jurisdiction. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1115 (9th Cir. 1984).

Although both regional and extraregional rates are established by the Administrator under identical statutory standards, FERC review of extraregional rates for sales of nonfirm energy is undertaken pursuant to section 7(k) of the Northwest Power Act. 16 U.S.C §839e(k). The Commission reviews extraregional nonfirm energy rates to ascertain that BPA has designed rates (1) having regard to the recovery of the cost of generation and transmission of such electric energy; (2) so as to encourage the most widespread use of BPA power; (3) to provide the lowest possible rates to consumers consistent with sound business principles; and (4) in a manner which

protects the interest of the United States in amortizing its investments in the projects within a reasonable number of years. United States Department of Energy--Bonneville Power Administration; Opinion No. 250, 36 FERC ¶61,335, 61,798 (1986).

Pursuant to §7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), FERC has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. 300. The Commission recently adopted a final rule amending these procedures effective July 6, 1987. 52 FR 20,704 (1987).

CHAPTER II

PRELIMINARY ISSUES

A. Introduction

The issues discussed in this chapter are treated separately because their resolution affects other issues throughout BPA's ratesetting process. The chapter first deals with issues related to BPA's forecasts of key commodity prices, specifically the forecasts of aluminum and fossil fuel prices. Second, BPA's forecasts of aluminum DSI loads are discussed. Third, BPA's forecast of surplus firm power sales is addressed. Finally, the issue of price elasticity of PF class loads is discussed.

B. Key Commodity Prices

BPA developed forecasts of the future market prices of several key commodities which influence its revenues, not only through their impact on loads of certain customer groups, but through the direct impact on the rates paid by those customer groups. Forecasts were prepared for the market price of aluminum in U.S. markets, which affects both the loads of BPA's aluminum DSI customers and the average rate paid by those customers under the VI rate schedule. Forecasts also were made for residual oil and natural gas prices in California utility markets, which affect both BPA's sales to Southwest utilities over the Intertie and the average revenues received for those sales.

1. Aluminum Prices

The market price of aluminum is the single most important variable used in the aluminum forecasting model. A lower price of aluminum tends to lower expected production and electric load levels and resulting revenues. A more optimistic price increases loads and revenues.

Issue

What should be the forecast of aluminum prices?

Evaluation of Positions

Aluminum price forecasts and associated ranges were published in the initial loads and resources study. BPA, E-BPA-03A1. Aluminum price projections in the study were based on reports by Chase Econometrics and Resource Strategies, Inc., firms that BPA has relied on in the past for aluminum industry forecasts. The RSI Price Forecast is the more optimistic of the two and was used for the high case. The Chase forecast was used for the low case. The Medium Case was a weighted average of the RSI and Chase forecasts, weighted 65 percent RSI and 35 percent Chase. The initial price projections (in current dollars) over the rate period (10/87 to 9/89) average

55.4¢/lb. for the low, 64.8¢/lb. for the medium, and 69.8¢/lb. for the high Case. The Forecast was updated for supplemental testimony to reflect the latest available information from these consultants. Sugiyama/Spies, BPA, E-BPA-33. The ranges were not changed from initial testimony.

PPC, WPAG, and WUTC suggest that the medium price forecast may be conservative in view of current aluminum price strength. Initial Brief, PPC, B-PP-01, 22; Initial Brief, WPAG, B-WA-01, 23; Exceptions, WPAG, R-WA-02, 8; Exceptions, WUTC, R-WU-02, 2. However, no party provides evidence or indication of the factors underlying the current price strength, or how long it is expected to continue. As indicated in initial testimony, BPA seeks to update its forecasts of aluminum prices to reflect recent actuals as well as new information and market outlooks presented by industry consultants. Sugiyama/Spies, BPA, E-BPA-09, 13. The latest industry outlooks suggest that the current price strength is based on short-term factors, such as strong seasonal demand and speculation over possible labor strikes, that will not be maintained over the mid- to long-term. Prices are expected to return to levels previously forecasted.

Decision

The medium price forecast will be adjusted to reflect recent actual market prices as well as the outlook for prices over the near term. Actuals are updated to April 1987. The forecasted prices for May through October 1987 are increased to reflect continuation of current price strength. From November 1987 onward the price forecast is unchanged from supplemental testimony. A complete listing of the revised price forecast is included in the Final Loads and Resources Study, FS-BPA-03.

2. Fossil Fuel Prices

Projections of oil and natural gas prices are prepared for use in estimating the marginal cost of oil and gas generation in California. Since BPA's sales of surplus firm power and nonfirm energy in California must compete with those generating resources, the price BPA can obtain for the power in that market is determined by California utilities' marginal cost of generation. Lower fossil fuel prices reduce the marginal cost of generation in California and lead to lower prices for the power BPA has available for sale in the PSW. This results in lower BPA revenue. Conversely, higher fossil fuel prices increase the marginal cost of generation in California and lead to higher BPA revenues.

Issue

What oil and gas price forecasts should be used to project BPA's revenue from extraregional sales?

Evaluation of Positions

BPA developed the oil and gas price forecasts used to prepare the export revenue forecast for the initial rate proposal. These oil and gas forecasts were published in the Initial Loads and Resources Study. BPA, E-BPA-03A1. They were not revised in subsequent BPA testimony.

BPA developed Low Case and Base Case oil and gas price projections using DRI's World Oil Simulation Model and a linear regression that links electric utility oil and gas costs to crude oil prices. DRI's World Oil Simulation Model was run separately for the Low Case and Base Case projections based on different assumptions for OPEC crude oil production levels and world oil demand elasticities. Moorman, BPA, E-BPA-11, 7 and 10.

The Low Case price projections (in current dollars) over the rate period (10/87 to 9/89) average $9.65/bbl for residual oil and $1.64/mmBtu for natural gas. The Base Case price projections over the rate period average $15.14/bbl for residual oil and $2.46/mmBtu for natural gas. The Base Case fuel price projections were used to produce BPA's export revenue forecast, while Low Case projections were used for contingency planning. Moorman, BPA, E-BPA-11, 1.

BPA modified DRI's World Oil Model to solve for a higher level of OPEC oil production and a higher demand elasticity for oil than originally contained in the model. BPA then ran the World Oil Model to produce world oil price projections. BPA converted these world price projections into oil and gas price projections for the PSW, using regression analysis. Moorman, BPA, E-BPA-11, 6. WPAG asserts that for the Base Case the staff changes to the World Oil Model were unjustified and resulted in overly conservative projections for PSW oil and gas prices. McGary et al., WPAG, E-WA-02, 34-35. WPAG asserts further that rather than use its own price forecasts, BPA should use the average of gas price forecasts from DRI, Wharton, and Oil and Gas Journal (OGJ) instead. McGary et al., WPAG, E-WA-02, 36. The Northwest Parties estimate that PSW fuel prices should be near BPA's average system cost, or about 25.0 mills per kWh. Opatrny/Peters, NWP, E-NP-01, 15. (The 25 mills/kWh is equivalent to $2.50/MMBtu at a 10,000 Btu/kWh heat rate.)

WPAG's assertion that raising the oil demand elasticity in the World Oil Model lowered the price projections is in error. Raising the demand elasticity caused the price projections to be higher, not lower. Moorman, BPA, E-BPA-44, 5 and 6. Moreover, modification of the elasticity was justified by a review of the literature and DRI's own admission that the oil model's original elasticity is very contentious. Moorman, BPA, E-BPA-44, 6. WPAG's observation that increasing the assumed level of OPEC oil production in the Oil Model reduced the price projections is valid, but only during FY 1988. By FY 1989, the upward effect of raising the oil demand elasticity in the model becomes strong enough to offset the downward effect of increasing production levels in the model. As a result, the price projections were largely unaffected by the model changes during FY 1989. Helgeson/Waddington, PNGC/PGP, E-PG/PN-01, 15 and attachments; Moorman, BPA, E-BPA-11, Attachment L.

The lower price projections for FY 1988 compensate for the fact that gas prices are expected by many experts to remain unusually low in relation to oil prices through FY 1988. Moorman, BPA, E-BPA-11, 9.

Subsequent to WPAG's testimony recommending the use of the average of available DRI, Wharton, and OGJ price projections instead of staff price projections, both DRI and Wharton released new projections. These new forecasts, along with new information on natural gas transmission rates in California, lowered the average of the three projections recommended by WPAG. Moorman, BPA, E-BPA-44, 1-2. As a result, when averaged over the entire rate period, BPA's projections for California ($2.45 per MMBtu) are slightly on the high side of the other projections ($2.38 per MMBtu) instead of on the low side as asserted by WPAG. Moorman, BPA, E-BPA-44, 1-2 and Attachment A. BPA's projections for California are very close to OGJ in FY 1988 and Wharton in FY 1989. Moorman, BPA, E-BPA-44, Attachment A.

WPAG and WUTC recommend that the Base Case oil price forecast be updated to reflect current conditions in which OPEC, by restraining its oil production over the last six months, has caused world oil prices to increase to the $18-20 per barrel range. Exceptions R-WA-02, 8; and R-WU-02, 1-2. This recommendation is sound. The Base Case forecast projected that not until FY 1989 would countries within OPEC show enough unity to restrain production so as to raise the price of crude oil to $18.00 per barrel. Moorman, BPA, E-BPA-11, 4-5. Moorman, BPA, E-BPA-44, Attachment A. As a result, the Base Case forecast for the price of crude oil in FY 1988 averaged only $15.50. Saudi Arabia has now reportedly adopted a goal to maintain stable world oil prices around $18 per barrel. FS-BPA-03. Therefore, while it is reasonable to raise the Base Case crude oil price forecast to a constant level of $18 per barrel over the 1988-89 rate period, it is unreasonable to raise it much above that level.

For reasons described in BPA's Final Loads and Resources Study (FS-BPA-03), it would be imprudent to update (increase) the Base Case gas price forecast along with the oil price forecast.

Decision

In calculating the rate schedules for the 1988-1989 rate period, the base Case forecast for the price of California residual fuel oil will be raised to a constant level of $18.50 per barrel from an average of $13.86 in FY 1988 and $16.41 in FY 1989 to reflect both recent California oil prices and current OPEC pricing strategy. The Base Case forecast for the California spot price of natural gas will not be changed from that of the initial rate proposal for two reasons. First, although the gas price projection was originally calculated with gas prices constrained by oil prices, gas prices are now estimated to be constrained in a similar fashion by the nation's gas surplus instead. Second, the gas price projection is similar to estimates prepared by mainstream forecasters, including the average recommended by WPAG ($2.45 vs. $2.38 per mmBtu).

C. Forecasted Aluminum DSI Loads

Load forecasts for all of BPA's major customer groups are prepared and compiled by BPA annually and revised periodically. BPA's load forecasts project future power needs for the Pacific Northwest. These forecasts are used throughout BPA in power planning activities and in rate development. Except for testimony related to the issue of price elasticity generally, BPA's load forecasts used in this proceeding were not opposed. As a result, they will not be revised, except to reflect some recent developments in actual loads of aluminum DSIs, which are discussed below. The issue of price elasticity in utility loads is discussed in section E.

Load Forecast

In the Aluminum Smelter Model (ASM) used by BPA to forecast aluminum industry loads, a projected price of aluminum is compared to variable production costs at each of the region's smelters. If price exceeds cost, the smelter is assumed to increase production. If a smelter is not covering costs, it will curtail production. For this proceeding, a number of changes were made to the model, inputs, and assumptions regarding individual plant operations. The ASM was modified to allow incorporation of the Variable Industrial Power rate parameters. Production costs were updated to reflect the latest information, including recent labor settlements. BPA, E-BPA-03A1.

Issue 1

What should be the forecast of aluminum DSI loads?

Evaluation of Positions

In supplemental testimony BPA revised its initial DSI load forecast to reflect new information regarding two specific industrial customers. Sugiyama/Spies, BPA, E-BPA-33. In rebuttal testimony some smelter-specific loads were adjusted to reflect assumptions regarding the Conservation/Modernization Program and the restart of idle smelter capacity, but these adjustments were offsetting and the total DSI load level was unchanged. Sugiyama/Spies, BPA, E-BPA-45. The adjustment for Con/Mod is discussed in Chapter IV. Since filing rebuttal testimony, however, new information has become available which affects the load forecast. Specifically, potlines have been restarted at the Troutdale, Mead, and The Dalles aluminum smelters. Furthermore, the higher aluminum prices in the near term, proposed in a prior ROD issue, affect the level of loads.

WPAG and WUTC argue for the inclusion of load at the Goldendale smelter. Exceptions, WPAG, R-WA-02, 9; Exceptions, WUTC, R-WU-02, 2. The current DSI load forecast assumes Goldendale's electric will remain at zero throughout the forecast period. Sugiyama/Spies, BPA, E-BPA-33, 3. Including electric load at Goldendale would result in an overly optimistic DSI load forecast for two reasons. First, there is risk associated with the successful operation of this particular smelter as well as the other three smelters that have recently

transferred ownership to thirty-capitalized, non-integrated operations. Spies, BPA, TR, 1972. Second, although prices recently have demonstrated short-term strength, there is a risk, reflected in the low price scenarios that prices may fall again to levels where curtailments of smelter production and load levels are inevitable. Loads and Resources Study, bPA, E-BPA-03A1, 5. Rather than attempt to forecast the timing and location of smelter curtailments during periods of weak prices, the forecast of average load was constrained by assuming zero load at Goldendale. This assumption in effect acts as a proxy reflecting the risk of potential smelter shutdowns generally.

Decision

BPA will increase the loads in the near term (1987) to reflect new information and price assumptions. Recent potline restarts at Mead, Troutdale, and The Dalles will be reflected in the load forecast. A complete listing of new aluminum loads compared to those in supplemental testimony is included in the Final Loads and Resources Study. The nonaluminum loads remain unchanged from supplemental testimony. Load at the Goldendale smelter will not be included in the forecast.

Issue 2

How much savings should be attributed to the Conservation/Modernization program?

Evaluation of Positions

BPA incorporated, in its DSI load forecast, savings attributable to the Con/Mod program of approximately 80 MW in FY 1988 and 145 MW in FY 1989. Sugiyama/Spies, BPA, E-BPA-45, Attachments 1 and 2. Testimony of WPAG suggests that the DSI forecast is overly conservative because of the inclusion of this level of Con/Mod savings. Initial Brief, WPAG, B-WA-01, 24. WPAG cites four reasons why this estimate of savings may be high: (1) BPA has received no explicit Con/Mod proposals, (2) time lags are involved in implementing Con/Mod and achieving savings, (3) budget constraints preclude the level of savings assumed, and (4) Con/Mod savings will be offset by higher smelter operating levels. Oral Argument, WPAG, TR 2883.

The DSIs indicate that they expect a "robust response to the program" and that 140 MW is a reasonable estimate. Oral Argument, DSI, TR 2924. Further, the program budget would, in fact, allow eventual savings of more than 140 MW. Actual time lags will depend on plant type, modernization package, and corporate strategy. Since the Con/Mod program was announced in June, proposals have been received from seven of the smelters. The anticipated savings from these proposals would exhaust the budget if the smelters operated at full production levels.

The load forecast has Con/Mod savings being achieved slightly ahead of the ramped-in program budget. It is therefore appropriate to delay the assumption of savings so that it more closely matches the budget. This would raise loads about 20 MW in FY 1988, 55 MW in FY 1989, and 15 MW in FY 1990. The last

concern raised by WPAG does not take into account the fact that the smelters in the forecast that are modernized are operating at full capacity. Sugiyama/ Spies, BPA, E-BPA-45, Attachment 1. That is, the 140 MW is energy savings achieved at full operation. At lower operations the savings (and the Con/Mod payments) would be reduced. Overall, the FY 1988-1989 DSI forecast has the aluminum smelters operating at 76 percent of capacity (84 percent if one excludes the one closed smelter), including the Con/Mod savings. This compares to the past 5 years' average smelter operating level of 74 percent.

Decision

The eventual achievement of 140 MW for Con/Mod is reasonable and is in line with budgetary constraints. The timing of the savings should be revised, however, to reflect the ramp-in of the Con/Mod budget. The revision will be included in the DSI load forecast in the Final Loads and Resources Study, FS-BPA-03.

D. Forecasted Surplus Power Sales

Issue

How much surplus firm power should BPA assume that it will sell at fully allocated cost?

Evaluation of Positions and Decision

In the initial proposal BPA estimated that it could sell as much as 250 average megawatts of surplus firm power at fully allocated cost. This assumption considered the status of BPA's negotiations with numerous California and PNW utilities, including a proposed contract with Southern California Edison, whose contract principles were signed and filed before the Commission. Noguchi, BPA, E-BPA-13, 1; Metcalf/Schaller, BPA, E-BPA-57, 1. BPA's assumption that 250 aMW could be sold at fully allocated cost balanced the projection of only moderate fuel price recovery during the rate period with the expectation that some short-term transactions or long-term contracts would provide for sales during FY 1988-1989 at greater than spot market prices. Id., 3. For example, the assumption of 250 aMW sold at fully allocated cost is equivalent to 500 aMW being sold at a rate halfway between spot market prices and fully allocated cost. Id.

Several months have passed since the initial proposal was published. Conditions in the market for surplus firm power and nonfirm energy have led in recent years to surplus power transactions at rates substantially below cost. Recent declines in gas and oil prices have reduced significantly BPA's short-term prices for sales of surplus firm power. Metcalf/Schaller, BPA, E-BPA-26, 2; Noguchi, BPA, E-BPA-13, 3-4. BPA projects only moderate fuel price recovery during the rate period. Noguchi, BPA, E-BPA-13, 3. BPA recently reassessed the likely outcome of its current negotiations, and concluded that a more likely estimate would be that BPA may sell 180 average megawatts of power in FY 1988 and 220 average megawatts of power in FY 1989. Furthermore, it appears likely that these sales will be made at an average

rate of 29 mills per kilowatthour. FS-BPA-06A, RAM Table LRB E-2. BPA's SL-87 rate proposal allows discounted rates in the near term to facilitate long-term sales as long as the rates over the contract term as a whole exceed the greater of BPA's Priority Firm rate or its opportunity cost. Schaller, BPA, TR 261; Metcalf/Schaller, BPA, E-BPA-57, 2.

WPAG asserts that the evidence in the record supports retention of the original Surplus Firm power projection. WPAG argues that an adjustment of this magnitude (reduction in forecasted export revenues of nearly $40 million) should not have been presented for the first time in the draft ROD. Exceptions, WPAG, R-WA-02, 10-12. The WPAG position fails to consider the changing conditions discussed in the previous paragraph. The surplus power assumption has been changed to reflect actual negotiating experience since the initial proposal was presented. BPA placed a great deal of reliance on the expected outcome of its negotiations with Southern California Edison (SCE). These negotiations have faltered. While BPA continues its discussions with SCE, for purposes of this rate case, it would be imprudent for BPA to rely on an assumption that sales will commence under this proposed agreement during the rate period. Retention of the original surplus assumption would be inappropriate in light of these conditions, and would yield an inaccurate forecast of potential surplus revenues.

Decision

BPA will assume for the final proposal that 10 average megawatts will be sold at fully allocated costs in FY 1988 and FY 1989, for the purpose of developing the SL rate. BPA will also assume that 170 average megawatts of surplus firm power will be sold in FY 1988 and 210 average megawatts will be sold in FY 1989. These sales will be assumed to be made at 29 mills per kWh.

E. Price Elasticity

Price elasticity of demand is a measure of the extent to which the quantity of a commodity (in this case, electricity) demanded changes as a result of changes in the price of the commodity. Specifically, price elasticity is the ratio of the percentage change in demand to the percentage change in price which prompted the response. For most commodities, including electricity, price elasticity is negative. That is, a change in price leads to a change in demand of the opposite sign. The greater the elasticity, the greater a reduction in electrical load would be expected to result from an increase in electric rates. Elasticities greater in magnitude than -1.0 imply that increases in electric rates would lead to such large decreases in loads that revenues would go down as a result of higher electricity prices.

Discussions of elasticity presented in testimony can be separated into those related to retail (end-use) elasticity, including irrigation, and those related to wholesale (utility) elasticity.

Issue 1

Are retail price elasticities in BPA forecasts of PF class load generally reliable?

Evaluation of Positions

The load forecast for PF class loads is based upon: (1) an econometrically estimated model of retail loads for non- and small- generating public utilities and (2) forecasts of the generating public agencies taken from the 1986 PNUCC Northwest Regional Forecast. BPA, E-BPA-03, 7. Price elasticities for PF class loads can be calculated or inferred from the forecast models or assumptions.

PPC argues that recent estimates of the retail price elasticity are unreliable due to recent changes in fossil fuel and electricity prices. Peters, PPC, E-PP-04, 16. PPC extends, by inference, this general argument to the PF class elasticities embodied in the load forecast. Peters, PPC, E-PP-04, 16.

PPC argues that forecast electricity space heating penetration rates (contained in BPA's most recent long-term load forecast, Forecasts of Electricity Consumption, November 1986) are unreasonably high given data from Pacific Northwest natural gas distributors to document an increasing share of natural gas used in residential space heating. Peters, PPC, E-PP-04, 11. These sources report penetrations using a variety of conventions, not consistent with each other or those used in the forecast. In fact, depending upon the means of reporting the data, radically different conclusions can be reached using the same information. Moorman/Schneider, BPA, E-BPA-52, 5.

In support of past and expected changes in penetration rates, PPC offers cost data for high-efficiency gas furnaces to document a significant cost advantage over electric space heating equipment at current prices. Peters, PPC, E-PP-04, 11. These data are incomplete, however, and thereby distort the comparison to available electric space heating equipment. Moorman/Schneider, BPA, E-BPA-52, 7. Available high efficiency electric heat pumps were not included in the comparison. The addition of this type of equipment significantly improves the cost competitiveness of electric space heating equipment. Moorman/Schneider, BPA, E-BPA-52, 6.

The discussions of natural gas/electricity competitiveness described above relate to the level of the price elasticity of demand for electricity among PF class consumers. Moorman/Schneider, BPA, E-BPA-52, 2. PPC argues that competition resulting from recent changes in the relative prices of natural gas and electricity call into question the reliability of estimates of price elasticities available in the professional literature. Specifically, regional elasticities are expected to be higher than currently available estimates. Peters, PPC, E-PP-04, 19.

While the recent changes may have increased the elasticity, no alternative estimate of the level of the elasticity for PF class loads nor documentation demonstrating that the PF class elasticity is greater than one in absolute

value is offered by other parties. Moorman/Schneider, BPA, E-BPA-52, 4. Revenue recovery following a change in rates is dependent upon an elasticity being less than one in absolute value. Moorman/Schneider, BPA, E-BPA-52, 2.

PPC argues that the long-run elasticity is most relevant and that currently available estimates are theoretically too low. Peters, PPC, E-PP-04, 20. PPC cites an EPRI publication to document the availability of elasticity estimates greater than one (in absolute value). Peters, PPC, E-PP-04, 20. However, the authors of the EPRI study cited by PPC specifically evaluated the elasticity estimates and concluded that the larger estimates were inappropriately biased to the high side and that elasticity estimates of -0.10 for the short run and -0.75 for the long run are more appropriate. Moorman/Schneider, BPA, E-BPA-52, 5.

The relevance of the long-run elasticity is seen in the fact that some firms and households do make long-run (capital and locational) decisions within the rate period. Peters, PPC, E-PP-08, 4. Specific examples of this type of decision are offered by PPC. Peters, PPC, E-PP-04, 14. These examples represent decisions of a relatively small portion of PF class load, however, and the effect on total PF class loads is likely to be small and not jeopardize revenue recovery. Moorman/Schneider, BPA, E-BPA-52, 4.

Finally, it should be noted that the elasticities discussed on the record are those available in the literature. Peters, PPC, E-PP-04, 16, 20; Moorman/Schneider, BPA, E-BPA-52, 4, 7. Elasticities implicit in the load forecast for the PF class were not addressed directly.

Decision

The elasticities implicit in the PF class load forecast are within the bounds established in the literature. No alternative estimate of the elasticity for PF class loads has been offered. As a result, no changes in the model specifications or assumptions underlying the PF class load forecast are necessary. The load forecast for the PF class will remain as submitted in the Initial Loads and Resources Study, E-BPA-03.

Issue 2

Has the elasticity of demand for irrigation customers in particular been appropriately considered?

Evaluation of Positions

Based on considerable work with the BPA agricultural model and by examination of the works of Whittlesey and of McKusick and the Horner and Wessells NIU work BPA concludes that irrigation load demand is inelastic and ranges from -.25 to -1. BPA also concludes that it will remain inelastic over the rate period. Moorman/Schneider, BPA, E-BPA-52, 11, 12 and 17.

NIU states that the elasticity of demand for irrigation electricity is larger than estimated by BPA. Martin, NIU, E-NI-01, 7-12. NIU claims that

the elasticity can be expected to increase over the rate period to the point where it is elastic. Martin, NIU, E-NI-08, 8. NIU's position on the magnitude of existing elasticity is based on updating a study by Maddigan, Chern, and Rizy. NIU's position on the magnitude of price elasticity in the future is based on informed speculation about the future by an expert in farm policy and agricultural economics. Martin, NIU, E-NI-08.

Updating the Maddigan, Chern, and Rizy Farm Energy Model by Horner and Wessels for NIU produced an elasticity estimate of -.72. Martin, NIU, E-NI-08, 2. NIU's informed speculation about elasticity in the rate period is based on arguments concerning no change in farm technology, increased opportunities for farmers to take land out of production afforded by the 1985 farm bill, the effects of the 1986 tax law on farm conservation investment, and on an argument that farmers will shift to less water-intensive crops.

The NIU argument for increasing elasticity based on no agriculture technology change is unrealistic and is contradicted in NIU's own testimony on agricultural technology, Martin, NIU, E-NI-01, 8 as well as by commonly accepted data and studies. Moorman/Schneider, BPA, E-BPA-52, 14. Furthermore, the linear demand curves in the theoretical argument are not realistic. Aggregate farm product demand curves are more realistically composed of segments having various slopes and elasticities. Moorman/Schneider, BPA, E-BPA-52, 14.

NIU has extrapolated the actions of all farmers in taking land out of production in response to the 1985 farm bill to sprinkler irrigators as well. Martin, NIU, E-NI-08, 6. It is not likely that a significant amount of sprinkled land will be affected by the farm bill over the rate period because nonirrigated land is drawn out of production first by the bill. Moorman/ Schneider, BPA, E-BPA-52, 15.

The effects of the 1986 tax law on irrigation conservation investment cannot be assessed. The law's effects will be overshadowed by other farm economic factors. Moorman/Schneider, BPA, E-BPA-52, 15.

Decision

Irrigation electricity price elasticities may be somewhat higher than previously estimated by BPA. However, evidence is not persuasive that the elasticities are greater than -1.0. Irrigation load will be largely unresponsive to electricity price changes. Irrigation elasticity of demand has been appropriately considered by BPA.

Issue 3

Should BPA revise its projections of revenues and costs based on an assumption that PF customers have power supply options that are more cost-effective than purchases of PF power from BPA?

Evaluation of Positions

PGP argues that rate design responses to short-term problems are leading PGP members to reevaluate their relationship with BPA. Hardy et al., PGP, E-PG-01, 4-8. PGP claims that certain BPA rate measures such as the DSI incentive and variable rates, the elimination of the DSI customer charge, the nonfirm rate cap, the irrigation discount, and the "skewing" of capacity/ energy cost allocations will lead PGP to look for alternative resources that have greater operational flexibility and lower costs than purchases from BPA. Garman et al., PGP, E-PG-02, 7-17.

PPC argues that BPA should not assume that the loads of the PF customers are inelastic, even if portions of that load may be inelastic in the short run. Peters, PPC, E-PP-04, 1. PPC provides an extensive analysis of the costs of a combustion turbine (CT) generation facility that could be built by PF customers as an alternative to PF purchases from BPA. A forecast of the cost of this CT is compared to two projections of BPA's PF rate. Peters, PGP, E-PP-04, 2-7. PPC uses the results of this comparison and conclusions on the level of retail price elasticity to argue that the PF customers can no longer be considered a "deep pocket," which they assert is BPA's current position. Peters, PPC, E-PP-04, 16. PPC argues that the short-run steps that BPA is taking to improve its financial conditions will drive PF customers to other resource alternatives and leave BPA in even worse financial condition. Exceptions, PPC, R-PP-01, 4-5.

WPAG provided data indicating that the PF customers' share of the regional energy market at the retail level has been eroded due to past increases in the PF rate. WPAG claims that these customers have initiated efforts to locate power supply options which are likely to remain stable over time. McGary et al., WPAG, E-WA-02, 3-10. The issue of the price elasticity of demand for electricity at the retail level is addressed in the previous issues.

BPA does not dispute that past rate increases have reduced its competitive position relative to alternative energy sources. Melton/Armstrong, BPA, E-BPA-53, 2. However, BPA has taken considerable efforts to stabilize loads and revenues and to bring costs under control. In fact, under BPA's supplemental rate proposal, rates will have increased at an average annual rate of only 1.7 percent between November 1983 and September 1989. Melton/Armstrong, BPA, E-BPA-53, 3. Based on BPA's final proposal, this rate of increase has been reduced to 1.4 percent. Even though the increase for the coming rate period is higher than that annual average, BPA's long-term projections of the PF rate increase at a rate at or below the general rate of inflation. Melton/Armstrong, BPA, E-BPA-53, 2-3, Attachment A.

BPA's review of the resource alternatives available to PF customers indicates that PF purchases from BPA will continue to be the cost-effective alternative for these customers. This is true even for relatively pessimistic projections of the PF rate. Melton/Armstrong, BPA, E-BPA-53, 4-5, Attachment A. The PPC analysis of the CT alternative also indicates that the CT will be more expensive than purchases under the PF rate. This is true even under a "worse case" projection of the PF rate. Peters, PPC, E-PP-04, 2-7, Attachment A; Melton/Armstrong, BPA, E-BPA-53, 4. PPC also notes that

conditions could change, such as lower than expected natural gas prices, and the CT could become less expensive. PPC adds that the utility might also value diversity of generation sources. Peters, PPC, E-PP-04, 6-7. However, the uncertainty that can affect the relative magnitudes of PF purchases and alternative resource costs can also work to make the comparison look more favorable to the PF rate. PGP responds that other resources are attractive even at higher prices if their prices are more predictable and are under customers' control. Exceptions, PGP, R-PG-01, 4-5. Again, BPA's review included pessimistic projections of the PF rate. However, if a utility concludes that goals not based on cost-effectiveness are important, then that utility will continue to pursue those goals. Melton/Armstrong, BPA, E-BPA-53, 6.

BPA also recognizes that its review of alternative resources is not definitive. BPA encourages its customers to provide any evidence or analysis that would indicate that PF purchases from BPA are not the best value in the region. Melton/Armstrong, BPA, E-BPA-53, 5-6.

Finally, PGP's concern that BPA rate actions, such as the DSI incentive and variable rates and the nonfirm energy rate cap, are taken at the expense of other customers is unfounded. These actions broaden, or prevent the narrowing, of BPA's revenue base and help to keep rates lower than they would otherwise be. Melton/Armstrong, BPA, E-BPA-53, 6-7.

Decision

No convincing evidence has been provided that would indicate that significant quantities of cost-effective resource alternatives to PF purchases exist. Therefore, no change in the projected revenues and costs for the rate period is required based on this issue alone. However, BPA takes its obligation to provide the lowest possible rates consistent with sound business principles very seriously. BPA has taken and continues to take steps to control costs and enhance revenues. The PF customers are not viewed as a "deep pocket" from which to recover revenues.

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CHAPTER III

RISK MANAGEMENT

A. Introduction

During the current rate period (July 1, 1985 through September 30, 1987) BPA has suffered substantial revenue underrecoveries from unanticipated adverse events. The Risk Assessment Analysis conducted by BPA indicates that the overall revenue risk faced by BPA during the upcoming rate period is substantial. BPA continues to face risks of revenue undercollection associated with low aluminum prices, low regional employment levels, low natural gas and oil prices, reduced surplus firm power sales, and adverse water conditions. Wedlund/Luttmer, BPA, E-BPA-34, 5. Consequently, BPA's initial testimony considered the need for, and structure of, a comprehensive risk management strategy.

On the question of practical need, BPA identified risks facing BPA that amounted to $413 million on an annual basis. Melton/Meyer, BPA, E-BPA-17, 4. Those "risks" were identified by BPA because, although BPA utilizes what it believes to be the most reasonable forecasts available, there is uncertainty to any forecast. No party disputed the amount of risk identified by BPA. Initial Brief, WPAG, B-WA-01, 7; Oral Argument, APAC, TR 2852. The $413 million was viewed by BPA as a considerable amount of risk when compared to BPA's planned amortization payment in FY 1988 of $183.2 million and FY 1989 of $148.1 million. BPA, FS-BPA-01, v.

At the same time, BPA presented a disquieting picture of its past financial performance. BPA had to exercise its authority to reschedule amortization payments every year between 1974 and 1983; it deferred interest payments in FYs 1979, 1980, 1982, and 1983; the recorded net revenue loss for the FCRPS was $65 million in FY 1986, with FY 1987 looking even worse; and the FCRPS current balance of accumulated net revenues as of September 30, 1986, was a negative $373 million. Melton/Meyer, BPA, E-BPA-17, 4. BPA expects that by the end of FY 1987, accumulated net revenues will total negative $560 million. FS-BPA-01A, Chapter 6.

BPA is subject to a number of statutory obligations and constraints. Section 7(a) of the Northwest Power Act obligates BPA to establish its rates to recover its costs consistent with sound business principles; FERC reviews BPA's rates to determine whether they are sufficient to "assure" repayment of the Federal investment of the FCRPS over a reasonable number of years, after first meeting the Administrator's other costs. 16 U.S.C. section 839e(a)(1) & (2). At the same time, section 7(a) references Sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. section 838) and Section 5 of the Flood Control Act of 1944 (16 U.S.C. section 825s). Those sections, in essence, also dictate that BPA establish its rates to recover its costs and to encourage the most widespread use of power at the lowest possible rates consistent with sound business principles.

Given the potential that the risks identified by BPA could occur, and the legal requirements imposed upon BPA's ratemaking, BPA's initial testimony

stated that sound business principles require that BPA take those risks into account in its ratesetting process so that it has a reasonable assurance of meeting its Treasury obligations and otherwise recovering its costs. When considering the $413 million risk and the scheduled amortization payments and the extreme volatility BPA has experienced with DSI, surplus firm power, and nonfirm energy sales, it was clear that risk mitigation measures are necessary. The only question remaining was the determination of the amount and design of the risk mitigation package, essentially a judgment call. Melton/Meyer, BPA, E-BPA-17, 10-11.

To reasonably assure cost recovery in light of the risks identified by BPA, and to begin to improve BPA's negative net revenue position if possible, BPA proposed a package of risk mitigation measures which included: (1) using nonfirm energy and surplus firm power sales projections based on the 1939 water year for developing rates; (2) Investment Service Coverage (ISC); and (3) a Cost Recovery Adjustment Clause (CRAC). These measures were proposed in combination to provide a reasonable balance between the conflicting goals of keeping rates as low as possible and assuring sufficient revenues to meet BPA's repayment obligations. Melton/Meyer, BPA, E-BPA-17, 9.

During Oral Argument, a Statement of General Principles was presented to the Administrator. This Statement, endorsed by several of the parties, presented the following positions: (1) BPA's risk mitigation package is based on an assessment only of BPA's maximum repayment exposure. The package should also be based on the probabilities that various levels of repayment shortfalls will actually occur. (2) BPA proposes to mitigate part of the risk by higher initial rates. The level of risk mitigation provided by higher initial rates should reflect the existing financial reserves available to BPA to cover revenue shortfalls. (3) BPA's proposed Cost Recovery Adjustment Clause contains a discontinuity designed to increase rates by $40 million in excess of the costs BPA failed to recover. Any second year rate adjustment should restore only actual costs BPA failed to recover during the first year; it should not retroactively attempt to recover ISC revenues in excess of BPA's costs for that year. (4) BPA's risk mitigation package attempts to accumulate additional financial reserves even though BPA expects revenues to be low. Instead of imposing higher rates when BPA's markets are weak, the risk package should be designed to accumulate limited additional reserves when BPA's revenues exceed its expectations and its costs. These reserves should be used in adverse years to minimize the rate increase needed to offset poor revenues. Oral Argument, DSI, TR 2838-2839.

BPA has carefully considered the parties' statement of general principles for each of the proposed risk mitigation measures and for the risk management strategy as a whole. As a result, a number of changes were made in the evaluation and design of BPA's risk mitigation package. An assessment of the probabilities associated with various levels of repayment shortfalls has been included in the Risk Assessment Analysis. Existing financial reserves have been considered in the determination of the level of risk mitigation. The Cost Recovery Adjustment Clause has been modified. BPA's Risk Assessment Analysis and risk management strategy are now consistent with these principles. Discussions of the suggestions are included in the issues in this chapter.

This portion of the Administrator's Record of Decision revisits BPA's initial proposal in light of the record developed on it, the record developed in support of alternative proposals advanced by the parties, and the arguments of all the parties and participants. Specific attention is devoted to: (1) the appropriate data and analyses, such as a probability analysis, that should guide the Administrator's exercise of judgment; (2) the total amount of risk mitigation to be included in BPA's rates; (3) the theoretical components of the risk mitigation package; and (4) the balance between risk protection included in the rates initially, with the amount included in a mid-course rate adjustment. The general legality of BPA's accounting for and providing protection against risk in its ratesetting was firmly established in BPA's 1985 rate case, was confirmed by the FERC, and will not be addressed here. 1985 Rates ROD, WP-85-A-02, 16-30. United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis and Terminating Dockets, Docket No. EF85-2011-022 et al., 6 (April 29, 1987).

B. Risk Assessment Analysis

1. Introduction

In its initial proposal BPA presented a Risk Assessment Analysis as one of the supporting analyses for the Risk Management Strategy, to quantify the potential revenue underrecovery BPA could face in FY 1988 and 1989. Wedlund/ Luttmer, BPA, E-BPA-14, 5. The analysis quantified identified risks by simulating the revenue impact of low aluminum prices, low fuel prices, low regional employment levels, warmer temperatures, reduced contractual surplus power sales, and critical (1930) water conditions. Potential revenue shortfalls were then compared to base case revenues to determine the overall amount of risk for the 2-year rate period. BPA, E-BPA-06A, 547-561. The Risk Assessment Analysis considered potential risks of underrecovery, and estimated a potential revenue shortfall of $413 million from the base case load forecast scenario used in the rate proposal.

A number of the parties presented analyses to aid the Administrator in determining the proper level of risk coverage. These proposals differed from that presented by BPA in both methodology and results. These proposals are discussed in the following section, along with issues relating to the methodology and purpose of the risk assessment analysis. A comparison of the proposals entered on the record (including that of BPA) is presented in FS-BPA-06, Appendix B, Table B-3.

2. Methodology

Issue 1

Should the Risk Assessment Analysis include consideration of the probabilities of occurrence for the identified risks?

Evaluation of Positions

BPA did not initially include probabilities in the Risk Assessment Analysis, since recent history has demonstrated that forecasting the risks BPA faces requires a large amount of subjective judgment. Wedlund/Luttmer, BPA, E-BPA-46, 6. No single forecast can anticipate all possible outcomes of events which are beyond BPA's control and which affect BPA's actual expenditures. Melton/Meyer, BPA, E-BPA-17, 5. Therefore, BPA's Risk Assessment Analysis was developed to determine the overall potential revenue shortfall BPA might expect to experience in the rate period. Wedlund/Luttmer, BPA, E-BPA-14, 5. This information then was used in the development of the risk management strategy.

The parties argued that judgment used to develop the risk management strategy should be informed and, as such, should be aided by the use of probability analyses. Oral Argument, PP&L, TR 2927; Initial Brief, PGP, B-PG-01, 25-31. The Statement of General Principles presented at Oral Argument asserted that BPA's package of risk mitigation measures should be based on the probabilities that various levels of repayment shortfalls will actually occur. Oral Argument, DSI, TR 2838-2839. PGP further asserts that the use of probabilities is essential to the determination of the level of risk coverage to be included in the rates. Initial Brief, PGP, B-PG-01, 28.

PPC states that BPA should first identify potential sources of risk, then determine probabilities of occurrence for those risks as a means of measuring the amount of risk to be covered by risk mitigation measures. PPC further asserts that BPA's customers should not be asked to pay for what PPC characterizes as an undefined, arbitrarily chosen, unquantified amount of risk, especially given the weak regional economy. Carr/Peters, PPC, E-PP-10A2, 5. PPC additionally asserts that BPA has itself used probabilities to screen events for the analysis of risk, and that it is clearly inconsistent for BPA now to reject the explicit use of probabilities proposed by parties in this case. Carr/Peters, PPC, E-PP-10A2, 4. WPAG supports PPC's position, and references BPA's use of probabilities in the Revenue Uncertainty Analysis conducted for the 1985 wholesale power rate proposal. Initial Brief, WPAG, B-WA-01, 10.

PPC and WPAG both presented specific probability analyses. The PPC analysis, in particular, received endorsement from both PNGC and PGP. PNGC also supports the analytical approach adopted by PPC in preparation of its proposal. Initial Brief, PNGC, B-PN-01, 9-10. WPAG states that, by not including probabilities of occurrence, BPA's Risk Assessment Analysis fails to provide any means of measuring the degree of protection obtained from any particular risk package. McGary et al., WPAG, E-WA-02, 13.

The Risk Assessment Analysis used by BPA was conducted to provide useful information to aid in the policy decisions concerning risk mitigation, and does not purport to be a specific expected value analysis. The Risk Assessment Analysis evaluates the impact of various individual risk factors on BPA revenue projections, compares alternative proposals for risk mitigation, and considers historical and forecasted revenues, market trends, commodity prices, and water conditions. FS-BPA-06, Appendix B. Additionally, as

recommended by the parties in the Statement of General Principles, Oral Argument, DSI, TR 2838-2839, the Risk Assessment Analysis includes an analysis of various levels of potential revenue shortfalls. FS-BPA-06, Appendix B, Table B-2. Risk mitigation policy decisions require consideration of many factors in addition to those presented in the Risk Assessment Analysis. These factors relate specifically to BPA's financial obligations and goals. Melton/Meyer, BPA, E-BPA-17, 9.

Decision

The parties are correct that an assessment of risk inevitably involves some consideration, if only subjectively, of probabilities of occurrence. Therefore, BPA has included in its final Risk Assessment Analysis consideration of probabilities of occurrence and potential levels of underrecovery under the various risk mitigation proposals. FS-BPA-06, Appendix B. It is clear, however, that no probability analysis in the rate case, including BPA's, completely captures the complexities of BPA's net revenue risks. Consequently, while the probability analysis is a useful tool for judging the relative protection provided by alternative risk protection packages, it is not the sole tool or even a determinative one for assessing risk. Nor is it an algorithm for determining the total coverage needed. Another component of BPA's assessment of risk is a comparison of BPA's revenues in recent years with its forecast of revenues at current rates for the rate period. FS-BPA-06, Table B-4.

Issue 2

Should potential power cost savings be subtracted from projected revenue shortfalls if loads decline?

Evaluation of Positions

BPA's Risk Assessment Analysis does not include an adjustment for potential power cost savings if potential revenue shortfalls materialize. Wedlund/Luttmer, BPA, E-BPA-46, 10. BPA's Risk Assessment Analysis assumes that the events causing such shortfalls would be unanticipated during the rate period, would continue for an uncertain length of time, and would cause unexpected load reductions. Id. BPA's analysis further assumes that if generation is reduced in response to these load reductions, any power cost savings would be offset by reduced revenues. Id.

OPUC asserts that the results of the Risk Assessment Analysis should be adjusted to reflect the power cost savings that would result from reduced loads when adverse events occur. Hellman, OPUC, E-OP-01, 5. The OPUC proposal states that production cost estimates should be subtracted from the overall level of risk exposure in order to obtain an estimated net revenue exposure. Hellman, OPUC, E-OP-01, 13. OPUC states that power cost savings could result from several alternatives: (1) reduced dependence on coal-fired generation; (2) rescheduled refueling of nuclear generation and extending the maintenance periods for those facilities; (3) reduction of outside power

purchases; and (4) reduced operation and maintenance costs for plants where production is curtailed, e.g., Hanford and WNP-2. Hellman, OPUC, E-OP-01, 10.

The OPUC position fails to consider that BPA is not currently relying on either coal-fired generation or outside power purchases to meet its firm load requirements. Wedlund/Luttmer, BPA, E-BPA-46, 10. Also, BPA has no control over the scheduled refueling of nuclear facilities in the Pacific Northwest. Thus, the only alternative available to BPA would be reductions in variable operation and maintenance costs. Cost savings from shutting down WNP-2 and Hanford for short periods of time because of unforeseen load reductions would probably not offset the additional loss of revenues that would occur as a result. Id.

Decision

There would be no net savings if Hanford or WNP-2 were shut down in response to unanticipated load losses. Also, reducing the revenue risk amount to reflect power cost savings resulting from these shutdowns would be appropriate only if load reductions and the length of their duration could be anticipated.

3. Determination of Revenue Risks

Issue

Should additional risks be considered in the Risk Assessment Analysis?

Evaluation of Positions

BPA's initial Risk Assessment Analysis focused on the major risks that have been identified: low aluminum prices, low fuel prices, low regional employment levels, warmer temperatures, reduced contractual surplus power sales, and poor water conditions.

PPC accepts as reasonable the major categories of risk identified by BPA, and uses these categories in their analysis. Carr/Peters, PPC, E-PP-03, 16. WPAG also endorses the risks identified by BPA and uses these in their analysis. McGary et al., WPAG, E-WA-02, 16.

BPA's witnesses on the risk mitigation package also indicated that BPA faces large risks related to its projections of program costs and control of expenditures. Melton/Meyer, BPA, E-BPA-17, 5. PPC states that if additional risks exist beyond those which were initially considered in the Risk Assessment Analysis, those risks should be identified, quantified, and included in the analysis. Carr/Peters, PPC, E-PP-10A2, 5. PPC did not choose to identify any such risks, however, or to include them in the PPC analysis.

Subsequently, BPA included additional data in the Risk Assessment Analysis concerning potential revenue risks associated with reservoir levels, varying levels of deferred borrowing authority due to potential differences in FY 1987 revenues, and potential cost variations. These data were presented in the

Draft Record of Decision. DROD, WP-87-A-01, 66. In response, PPC stated that introduction of the new data violates section 7(i) procedural requirements, and therefore cannot be relied upon by the Administrator. Exceptions, PPC, R-PP-01, 3. The new data was presented as part of the Risk Assessment Analysis in the DROD in response to PPC's own suggestion concerning additional risks identified by BPA, and the parties' urging that BPA revise its initial Risk Assessment Analysis. This data expanded on previously presented information and served as a check on the overall validity of the analysis.

A consideration of potential variations in costs for the rate period is included in the Risk Assessment Analysis prepared for the 1987 final proposal. BPA's Revenue Requirement has been revised for the final proposal, and reflects significant reductions in BPA's budget. Roberts, BPA, TR 1661-1664; FS-BPA-06, Appendix B. These reductions place BPA at greater risk of costs exceeding budgeted levels. The cost variations are due to potential increases in interest expense, operating costs of net-billed nuclear plants, and net costs of the residential exchange program. Documentation for this category of risk is shown on the table entitled 1987 Rate Case Revenue Requirement Risk Assessment in FS-BPA-06A, Table B-5.

The surplus sales and rate assumptions have been changed to reflect actual negotiating experience since the initial proposal was presented. Aluminum prices and loads have also been updated to correspond with current conditions and assumptions used in the determination of the rates. These assumptions are discussed in Chapter II.

Decision

BPA will include the following risks in its Risk Assessment Analysis: low aluminum prices, low regional employment levels, warmer weather, reduced contractual surplus power sales, low fuel prices, poor water conditions, and potential variations in costs for the rate period. Since reservoirs are now likely to refill and the FY 1987 revenue forecast has been revised to reflect most of this year's actual results, reservoir levels and differences in the level of available deferred borrowing authority will not be included as risks.

4. Assignment of Probabilities to Risk Components

Issue 1

What water conditions should be considered in the Risk Assessment Analysis?

Evaluation of Positions and Decision

In BPA's initial proposal, critical (1930) water conditions were used to simulate poor water conditions to provide a comparison of revenues for this category of risk. Wedlund/Luttmer, BPA, E-BPA-14, 9. PPC expresses concern that selection of the 1930 water year provides an unrealistic assessment of the revenue risk BPA would face from poor water conditions. Carr/Peters, PPC, E-PP-03, 19. PPC argues that the Risk Assessment Analysis should consider revenues from nonfirm energy and surplus firm power that occur under

relatively low (but not critical) water conditions. PPC states that "the probability that revenues will be about equal to those associated with 1930 water conditions is only 2/40, or five percent." Id.

BPA agrees with PPC's assertion concerning the selection of the 1930 water year, and has used 1939 water conditions in subsequent analyses to reflect a more moderate level of risk from water conditions. Wedlund/Luttmer, BPA, E-BPA-46, 3. Use of the 1939 water year is appropriate, as this condition has a higher likelihood of occurrence than 1930 water conditions, and more closely simulates current water conditions.

Issue 2

What probability should be assigned to revenue risk associated with surplus firm power sales and gas and oil prices?

Evaluation of Positions

Continuing poor market conditions have caused BPA to revise downward its expectation of firm surplus contractual sales and revenues from the forecast in supplemental testimony. See Chapter II. These same considerations lead to the conclusion that the pessimistic case used in the Risk Assessment Analysis should assume that no firm surplus contractual sales would occur during the FY 1988 - FY 1989 rate period. This assumption has been assigned a probability of occurrence of 25 percent.

In the initial Risk Assessment Analysis, potential revenue underrecoveries resulting from low surplus firm power sales and from low gas and oil prices were treated as separate categories of risk. Wedlund/Luttmer, BPA, E-BPA-14, 7. BPA later agreed that these categories were interdependent and should be considered as one combined potential area of risk. Wedlund/Luttmer, BPA, E-BPA-46, Attachment C. Low gas and oil prices are an important element of risk because they affect prices received from surplus firm and nonfirm sales. However, they are by no means the only source (in addition to water conditions) of risk in this area. For the initial proposal, BPA did not assign a specific probability to this risk.

PPC also chose to combine the low estimates of surplus firm power sales and gas and oil prices in the PPC analysis. Carr/Peters, PPC, E-PP-03, 22. PPC assigned a probability of 16 percent for the combined low case for surplus firm power sales and gas and oil prices. Id., Attachment K. This probability was based on information provided by BPA for fuel prices. WPAG treated these categories somewhat differently in their analysis, in which they assign a probability of 15 percent to low gas and oil prices, and a separate probability of 0 percent to low surplus sales to California. McGary et al., WPAG, E-WA-02, Attachment 3.

For rebuttal testimony, BPA used the probabilities presented by PPC to aid in the comparison of the BPA proposal to the parties' proposals. At that time, BPA did not adjust these probabilities. Wedlund/Luttmer, BPA, E-BPA-46, 8-9. In assessing the probability of no surplus firm power sales and low spot

market prices, it is clear that low gas and oil prices are not the only circumstances than can result in this conclusion. These circumstancess include: marketplace competition, hydro conditions in California, regulatory changes, the rate at which new resources come on line in California, the difficulty in accurately modeling such a complex market, and competition from other generation in California and other areas. Wedlund/Luttmer, BPA, E-BPA-46A2, 3. The Risk Assessment Analysis has been updated with the new probability and surplus assumptions included for all party proposals. FS-BPA-06, Appendix B. Therefore, for BPA's final proposal, the pessimistic case probability of no surplus power contractual sales and spot market sales (at levels associated with the low gas and oil price forecast) has been increased from 16 percent to 25 percent to reflect additional firm and nonfirm market uncertainties.

Decision

It is appropriate to combine the risks associated with the forecasts of surplus firm power contractual sales and gas and oil prices as one category of potential revenue underrecovery. It is also appropriate to increase the combined probability to reflect additional firm and nonfirm market uncertainties. A probability of 25 percent will be assumed in the Risk Assessment Analysis for the revenue risk associated with surplus firm power sales.

5. Results of the Risk Assessment Analysis

Issue

How should BPA use the results from the Risk Assessment Analysis?

Evaluation of Positions

BPA has used the results from the Risk Assessment Analysis in the development of the risk management strategy. Melton/Meyer, BPA, E-BPA-17, 5; FS-BPA-06, Appendix B. Several potential areas of revenue underrecovery have been identified and included in the Risk Assessment Analysis. Wedlund/Luttmer, BPA, E-BPA-14, 6. Potential variations in forecasted costs have also been included in the analysis. FS-BPA-06, Appendix B. Historical and forecasted revenues, market trends, commodity prices, and water conditions have also been considered, as a check on the results of the analysis. Id., Table B-4. While the Risk Assessment Analysis attempts to fully address all potential revenue and cost variations for the rate period, such a determination requires a large amount of subjective judgment. The results of the analysis, therefore, provide useful information but do not provide the sole basis on which to base the risk management strategy. BPA's goal in conducting the analysis is to identify the major risks the agency faces which could result in substantial revenue shortfalls and to evaluate alternative risk mitigation proposals to measure the likelihood of meeting Treasury payments. FS-BPA-06, Appendix B.

A number of the parties acknowledge that analysis results should be considered along with subjective judgment in the determination of risk

coverage. PGP states that the amount of revenue protection must be based upon the probability of incurring revenue underruns. Initial Brief, PGP, B-PG-01, 25. This position is clarified in PGP's later statement that a determination of probabilities should be combined with judgment in determining the level of risk coverage to avoid providing coverage for the maximum risk. Oral Argument, PGP, TR 2937. The DSIs state that the Risk Assessment Analysis should provide information on revenues ranging from full recovery of costs to the maximum shortfall, and that this information should be used in determining the level of protection to be included in the rates. Oral Argument, DSI, TR 2925. WPAG indicates that its risk proposal includes probabilities and some judgment in determining the level of protection provided by the rates. Oral Argument, WPAG, TR 2896.

PPC acknowledges that both judgment and objective analysis should be used in the determination of the level of risk to be covered in rates. Carr/Peters, PPC, E-PP-10A2, 3. PPC presents an expected value analysis for likely downside events, while omitting consideration of potential revenue overrecoveries. PPC asserts in Oral Argument that, because PPC's proposed risk mitigation covers the negative expected value of revenue underruns, it gives BPA a virtual certainty of making its Treasury payment. Oral Argument, PPC, TR 2954. PPC claims that its methodology adds a significant conservative bias to the analysis. Initial Brief, PPC, B-PP-01, 12; Exceptions, PPC, R-PP-01, 1-4. PPC asserts, however, that the <u>total</u> maximum amount of risk that should be covered is $195 million, as determined in the PPC Two Year Risk Analysis. Carr/Peters, PPC, E-PP-10A2, 8.

PPC's proposed use of an expected value analysis is illogical in light of the purpose for conducting the analysis. An expected value analysis will indicate if the forecast is biased; that is, if the expected value of revenues, treating the forecasts of parameters as probability distributions, differs significantly from the revenues assuming average or base levels for each parameter. For such an analysis, both optimistic and pessimistic cases must be developed as in BPA's 1985 Revenue Uncertainty Analysis. BPA's risk management package was designed to assure that BPA would have a high probability of recovering its costs and making its Treasury payments. Melton/Meyer, BPA, E-BPA-17, 10. The expected value of revenues is irrelevant to such a goal. A simple example illustrates this point. A game in which a person's life savings is either totally lost or doubled depending on the outcome of a coin flip has an expected value of zero--it is a fair game. Most people would find this game far too risky--a 50 percent chance of losing their life savings would be unacceptable. Similarly, a risk package could give BPA zero or positive expected net revenues and still expose it to an unacceptable probability of not making its Treasury payment. It is true that the PPC has presented a conservative forecast of the expected value of revenue underruns. However, there is no reason to expect a conservative estimate of the wrong question (expected value) to yield the right answer (high probability of revenue recovery). PPC admitted that there is a 50 percent probability that BPA's revenue loss would exceed the protection provided by the PPC proposal. Peters, PPC, TR 2576.

PPC asserts that its analysis does not confuse the concept of expected value analysis with the goal of a high probability of making Treasury

payments. Exceptions, PPC, R-PP-01, 3. It is the PPC position that their expected value analysis has been based on a number of conservative assumptions, and therefore the PPC proposal of $195 million of risk coverage provides a sufficiently high likelihood (80-90 percent) that BPA will make its Treasury payments during the two-year period. Exceptions, PPC, R-PP-01, 3. BPA does not agree with this conclusion. The PPC proposal of $195 million would not recover the estimated revenue underrun from FY 1987 of approximately $400 million. BPA, WP-85-FS-BPA-12, Table A-16; FS-BPA-12, Table A-7. When the PPC proposal is considered in light of the overall risk of revenue shortfall during the FY 1988-FY 1989 rate period, there is approximately a 40 percent chance that BPA will be unable to make all of its scheduled Treasury payments over the 2-year period. FS-BPA-06, Appendix B, Table B-3.

Decision

A probabilistic Risk Assessment Analysis is useful as one of the analytical tools in determining the level of risk coverage required in a comprehensive risk management strategy. The analysis should assess the probability of covering costs and making Treasury payments provided by alternative proposals. The expected value of revenues does not define the total amount of risk protection needed.

C. Risk Management Strategy

1. Introduction

BPA faces large potential revenue shortfalls during the next rate period. A comprehensive risk management strategy was presented in BPA's initial proposal. BPA's proposed strategy addresses all risks, including cost and revenue risks, on a comprehensive basis that balances the goals of lowest possible rates, stable and predictable rates, timely payments to the U.S. Treasury, short- and long-run financial health of the agency, mitigation of cost overrecovery or underrecovery, and enhanced flexibility to respond to market conditions. Melton/Meyer, BPA, E-BPA-17, 5. These goals have been endorsed as appropriate and necessary by the parties to the rate proceeding.

There is overwhelming supporting evidence in the record for the adoption of a risk management strategy to address large potential revenue shortfalls. Most parties in this proceeding and many participants support BPA adopting appropriate measures to mitigate risks of net revenue underruns during the rate period, especially in order to repay the U.S. Treasury. The DSIs state that "BPA must take all steps to address the risk that BPA may be unable to meet its repayment obligation." Oral Argument, DSI, TR 2838. This position was specifically endorsed by APAC and WPAG. Oral Argument, APAC, TR 2848; Oral Argument, WPAG, TR 2880. PGP states that the justification for adopting a risk package must be recovery of costs over time, and that any rate increment to aid revenue recovery must be based upon the probability of revenue undercollection. Initial Brief, PGP, B-PG-01, 31-32. PPC supports adoption of a risk management strategy to assure that BPA's U.S. Treasury payments are made. Initial Brief, PPC, B-PP-01, 4. WPAG supports adoption of a package of measures to address risk based on the revenue fluctuations faced

and the likelihood of their occurrence, and on the financial reserves available to cover them. Initial Brief, WPAG, B-WA-01, 7.

BPA considered many factors when determining the overall amount of risk mitigation to be included in rates. Risk factors that influence projected rates were identified, and a Risk Assessment Analysis quantifies the potential revenue underrecovery BPA faces in FY 1988 and 1989. Wedlund/Luttmer, BPA, E-BPA-14, 5. Issues concerning this analysis are discussed in section B of this chapter. BPA also considered sound business principles, as BPA is statutorily obligated to establish its rates to recover its costs consistent with such principles. Melton/Meyer, BPA, E-BPA-17, 1. One sound business principle is that both short- and long-run considerations be taken into account. Setting rates as low as possible runs the risk of BPA having to reschedule its amortization payments. In the long run, the chances of BPA being subjected to repayment reform would be greater given such a repayment track record, with the consequence that rates would not be as low as they might otherwise have been. Melton/Meyer, BPA, E-BPA-17, 10. BPA's risk management strategy has carefully considered and balanced such considerations. Id.

Adoption of a risk management strategy is consistent with direction from FERC, which states that "BPA has been directed by this Commission to anticipate sales and revenue underruns in the development of the rates (23 FERC 61,378 (1983)), and has been allowed to include amounts in its rates for unforeseen contingencies (54 FPC 808, 811 (1975))." Docket No EF85-2011-011 et al., (April 29, 1987), 6. FERC also endorsed the concepts of Investment Service Coverage and use of 1939 water conditions for revenue forecasting in its approval of the 1985 rates. Id.

As a consequence of BPA's analysis, BPA determined that it could be reasonably assured of meeting its obligations through adoption of a package of risk mitigation measures. BPA's risk mitigation package is composed of (1) the continued use of the 1939 water assumption in forecasting revenues from surplus firm power and nonfirm energy sales for the purpose of rate design; (2) the continued inclusion of Investment Service Coverage (ISC) in determining the FCRPS revenue requirement; and (3) the introduction of the Cost Recovery Adjustment Clause (CRAC) designed to adjust partially for differences between planned and actual funds from operations during the first year of the rate period. Melton/Meyer, BPA, E-BPA-17, 5-6.

The proposed risk mitigation measures differ in purpose and characteristics and complement each other in addressing risks. In combination, the measures included in BPA's final proposal reflect a reasonable and prudent balance between rate levels and rate stability. Investment service coverage and a 1939 water assumption, which average $120 to $125 million annually, are included to assure that rates are initially sufficient to recover costs. A possible mid-term rate adjustment (the Cost Recovery Adjustment Clause), which could recover up to an additional $121 million, is included to help keep rates as low as possible initially, and yet assure that rates are adequate to ensure repayment over the 2-year rate period. On average, the protection afforded by the overall risk mitigation package is approximately $185 million per year, a little less than one-half the risk initially identified by BPA in the Risk

Assessment Analysis. Melton/Meyer, BPA, E-BPA-17, 11. Results of the current Risk Assessment Analysis indicate that, if the proposed package of risk mitigation measures is adopted, BPA still faces potential revenue shortfalls. FS-BPA-06, Appendix B, Table B-3; and Wedlund/Luttmer, BPA, E-BPA-46A, Attachment C, Table C-2.

The following section of the Administrator's Record of Decision presents issues relating to the risk management strategy, the level of risk coverage provided by the package of selected measures, and issues relating to the proposals presented by the parties. Each of the three measures is discussed separately in later sections of this chapter.

2. Level of Risk Coverage

Issue

What level of risk protection should be included in the rates?

Evaluation of Positions

In the initial Risk Assessment Analysis, BPA considered the identified categories of risk in isolation and in combination. Wedlund/Luttmer, BPA, E-BPA-14, 6. Rather than assign individual probabilities to each type of risk, BPA considered the overall level of risk and potential revenue undercollection for the rate period. Melton/Meyer, BPA, E-BPA-17, 4. A risk management strategy was then developed to address this risk, while balancing the goals of assuring cost recovery and keeping rates low initially. Id., 5. BPA is concerned with the total potential net revenue underrecovery resulting from various risks, rather than the precise amount of net revenue underrecovery to be associated with each potential risk. BPA uses the most reasonable forecasts available, but all forecasts reflect uncertainty. Id., 9. Whether events occur at precisely the same time, or whether they occur individually during a rate period, the overall net revenue underrecovery that occurs as a result is approximately the same.

In the Revenue Uncertainty Analysis conducted for the 1985 rate proposal, a potential revenue shortfall of approximately $400 million was calculated. 1985 Rates ROD, WP-85-A-02, 21. Historical revenue shortfalls also were calculated for FY 1985, FY 1986, and FY 1987 (estimated) and presented in testimony. Wedlund/Luttmer, BPA, E-BPA-46, Attachment A. Most current estimates of these revenue underrecoveries amount to approximately $164 million in FY 1985, $263 million in FY 1986, and an estimated $400 million for FY 1987. The Risk Assessment Analysis conducted for this rate proposal has identified a total potential annual revenue risk of $350 - $400 million. These results appear reasonable when historical patterns are considered. BPA is proposing adoption of a package of risk mitigation measures which will result in coverage of an average of $185 million of risk per year. This level is appropriate, given the potential that the underrecoveries identified by BPA could occur and all other factors. Melton/Meyer, BPA, E-BPA-17, 10. While the measures do not fully cover the identified level of risk, such complete coverage is not prudent or necessary in view of current economic conditions in

the Pacific Northwest. Id., 11. The selected level of coverage provides BPA with approximately an 89 percent likelihood of meeting Treasury obligations over the rate period, and keeps rates as low as prudently possible. FS-BPA-06, Table B-3.

In the PPC analysis, results indicate that the simultaneous occurrence of low water conditions, low oil and gas prices, low aluminum prices (and resultant loads), and a poor regional economy is extremely unlikely. The PPC analysis assigns a probability of occurrence of 3.5 thousandths of a percent to this combination of risks. Carr/Peters, PPC, E-PP-10A2, Attachment C, 6; Peters, PPC, TR 2664. PPC then concludes that the overall level of risk protection identified by BPA is too large. Oral Argument, PPC, TR 2955-2956; Exceptions, PPC, R-PP-01, 1-4. The results of the PPC analysis do not agree, however, with the established historical patterns for the region over the last several years. FS-BPA-06, Table B-4. PPC acknowledges that during 1986 and 1987 BPA experienced revenue shortfalls as a result of low gas and oil prices, low aluminum prices, and lower than average water conditions. Peters, PPC, TR 2672.

PPC recommends adoption of a package of risk mitigation measures that results in $195 million of risk coverage over the 2-year rate period. PPC asserts that this level of risk coverage, in combination with emergency reliance on deferred borrowing authority, will provide a nearly 100 percent certainty that BPA will make its Treasury payment. Oral Argument, PPC, 2954. The results of BPA's Risk Assessment Analysis, however, do not support that conclusion. When the PPC proposal is applied to proposed rates and rate assumptions, there is approximately a 20 percent chance that BPA will be unable to make some or all of its scheduled Treasury payment in FY 1988, and a 40 percent chance that BPA will be unable to make all of its scheduled payments over the 2o-year rate period. FS-BPA-06, Appendix B, Table B-3. Adoption of the PPC proposal would result in an unacceptably high chance of not making those payments. The consequences of deferring amortization payments are severe, and adoption of the PPC risk package, because of the high probability of deferring amortization, would be in violation of BPA's obligation to establish its rates to recover its costs consistent with sound business principles. Melton/Meyer, BPA, E-BPA-17, 1.

WPAG asserts that the overall size of the proposed risk package is too large and can be safely reduced without significantly increasing BPA's financial risk when all available financial reserves are considered. Initial Brief, WPAG, B-WA-01, 10. WPAG further asserts that proposed rates could be lowered by one full percentage point if the level of risk coverage was reduced by $25 million, and that the resulting probability of deferred amortization would still be in an acceptable range. Exceptions, WPAG, B-WA-02, 13-14. To accomplish this goal, WPAG proposes adoption of a package of risk mitigation measures which would consist of $80 million per year in Investment Service Coverage and $140 million in deferred borrowing authority. WPAG further proposes a second year adjustment of up to $140 million to replenish the deferred borrowing authority which may be utilized in the first year. Oral Argument, WPAG, TR 2886. The WPAG proposal provides a higher level of risk coverage than the PPC proposal, and results in an estimated probability of some or all deferred amortization of 13 percent in FY 1988 and 15 percent over

the rate period. FS-BPA-06, Appendix B, Table B-3. The WPAG proposal, however, assumes a higher level of deferred borrowing authority ($140 million) than is projected to be available to cover revenue shortfalls. Only about $110 million for deferred borrowing authority is expected to be available to BPA at the end of FY 1987 for the purpose of making future Treasury payments. FS-BPA-06, Appendix B; FS-BPA-01A, Chapter 6. BPA has considered the level of available deferred borrowing authority in the determination of risk protection, as recommended by the parties in the Statement of General Principles. Oral Argument, DSI, TR 2838-2839.

The proposed package of risk mitigation measures provides an average of $185 million of protection per year and is comprised of the three originally proposed measures. Each of these measures is discussed separately in later sections of this chapter. This proposal responds to suggestions and concerns raised by the parties in the Statement of General Principles. Oral Argument, DSI, TR 2838-2839.

Decision

As presented in the Draft ROD, BPA has lowered the level of risk protection provided by the package of risk mitigation measures from that presented in initial testimony. This reduction is appropriate to reflect customer concerns about negative impacts of rate increases and still achieve a high probability of making planned Treasury payments.

3. Selection of Risk Mitigation Measures

Many of the parties have presented alternate proposals for quantifying and addressing the identified risks. None of the parties' proposals supports continued use of the 1939 water assumption. Instead, they recommend various combinations of either Investment Service Coverage or an Amortization Reserve Account, some form of Cost Recovery Adjustment Clause or mid-term adjustment, and reliance on the use of deferred borrowing authority to mitigate risks. These proposals are summarized in FS-BPA-06, Appendix B, Table B-3. This table has been prepared to compare the various proposals in the rate case and to indicate the relative protection offered by each proposal when consistent assumptions are applied. Id.

Issue 1

What level of risk protection should be built into the rates, and what level of risk protection should be included as a mid-course adjustment in the event of a deterioration of BPA's financial performance during FY 1988?

Evaluation of Positions

BPA's initial testimony indicated that the tension between setting rates in a manner that assures cost recovery and that keeps rates as low as possible is a matter of balancing a number of competing policy considerations within the context of sound business principles. Melton/Meyer, BPA, E-BPA-17, 1, 9.

Several parties to the rate case agree that such a balancing is indeed called for and that such balancing is a matter of judgment. Initial Brief, WPAG, B-WA-01, 2, 7; Initial Brief, DSI, B-DS-01, 3; Oral Argument, PP&L/PGE, TR 2927; Initial Brief, PPC, B-PP-01, 3-4.

On the question of balancing risk mitigation by including a dollar amount of coverage in rates initially versus a potential mid-course adjustment, BPA again is guided by its judgment as to the appropriate balancing of the goals of assuring cost recovery versus keeping rates low initially. Additionally, BPA's risk management strategy reflects concern that BPA be able to meet planned payments to the Treasury out of current revenues. Melton/Meyer, BPA, E-BPA-17, 2. Numerous parties agree that such balancing is essentially a matter of policy judgment. Initial Brief, APAC, B-PA-01, 14; Oral Argument, APAC, TR 2932; Initial Brief, PGP, B-PG-01, 33-34; Oral Argument, PGP, TR 2938; Oral Argument, WPAG, TR 2944; Initial Brief, PPC, B-PP-01, 12-13; Oral Argument, PPC, TR 2953. BPA's risk management package strikes a reasonable balance, maintaining rates as low as prudently possible while providing for reasonable assurance of cost recovery. Melton/Meyer, BPA, E-BPA-17, 11.

The proposed package of risk mitigation measures includes an average of $120-125 million per year for Investment Service Coverage and the 1939 water adjustment. This package provides BPA with adequate protection to meet its Treasury obligations in FY 1988. FS-BPA-06, Appendix B, Table B-3. The proposal also includes the Cost Recovery Adjustment Clause, which addresses potential revenue shortfalls during FY 1988 that could jeopardize BPA's ability to meet its obligations over the rate period. These measures provide a reasonable balance between the goals of setting rates as low as possible and ensuring timely payments to the Treasury. Melton/Meyer, BPA, E-BPA-17, 11.

The PPC proposal includes a minimal level of initial protection ($45 million per year in an Amortization Reserve Account) and a mid-course adjustment ($105 million). Initial Brief, PPC, B-PP-01, 7. PPC states that this division of risk protection represents a reasonable compromise between the conflicting views and interests in the rate proceeding. Initial Brief, PPC, B-PP-01, 13. PPC also expressed concerns about the possible consequences of including too much risk protection in the initial establishment of the rates. It is the PPC position that some of the risks are: (1) the harm of charging more than the region can pay; (2) the risk of utilities seeking non-BPA sources of energy; and (3) political pressures that could result from over-collection. Initial Brief, PPC, B-PP-01, 3-4. PPC claims that its proposal balances the need to meet Treasury payments with these risks of over-collection. Oral Argument, PPC, TR 2952. However, under the PPC proposal, BPA would be unable to make its full FY 1988 Treasury payment if gas and oil prices continue at low levels and surplus sales produce minimal revenues. The risk of not being able to meet the FY 1988 Treasury obligation increases if aluminum prices fall below forecasted levels. Both of these categories of risk have severely impacted BPA revenues in recent years. FS-BPA-06, Appendix B, B-3; FS-BPA-06A, Table B-2. The PPC proposal provides too little initial protection and too little total protection.

ICUA states that BPA's risk mitigation package is improperly designed and will therefore encourage rate instability and unpredictability. Initial Brief, ICUA, B-IU-01, 4. ICUA claims that BPA's risk mitigation package improves BPA's financial position during a bad year, when customers can least afford it, and returns the money to customers in a good year, when BPA should be building reserves against future bad years and consolidating its financial integrity. Id; Exceptions, PGP, R-PG-01, 4-5. This position is also expressed by APAC, PPC and PNGC. APAC states that BPA should not attempt to build "equity" in the system at a time when a large segment of its market is weak and unable to contribute to improving BPA's financial position. Initial Brief, APAC, B-PA-01, 8. It is not BPA's intention to build an unreasonable level of equity. Rather, BPA has proposed a combined package of measures which will minimize the immediate rate increase, and provide a reasonable level of assurance of BPA's ability to meet its Treasury payments. As stated subsequently, the "equitebuilding" features of BPA's CRAC have been significantly curtailed. In addition, the potential of ISC to "build equity" has been lessened due to the lower amount of ISC finally adopted by BPA.

WPAG states that its primary goal in suggesting changes to the BPA risk package is to minimize the size of the rate increase while providing BPA with adequate revenue protection throughout the rate period. McGary et al., WPAG, E-WA-02, 23. This goal has been endorsed repeatedly by several of the parties. WPAG further asserts that the adopted risk package should strike a reasonable balance between unneeded rate increases and assuring timely repayment. Initial Brief, WPAG, B-WA-01, 7. BPA's proposed package meets this need.

Decision

BPA's proposed package of risk mitigation measures carefully balances the risk protection included in the initial rates with the risk protection necessary to protect BPA's financial position in FY 1989. The levels of the three measures in combination provide a reasonable assurance that BPA will meet its Treasury obligations, while maintaining the level of rates as low as possible consistent with sound business principles.

Issue 2

Will the inclusion of risk protection in the rates cause BPA customers to actively seek other sources of energy?

Evaluation of Positions

BPA is concerned about the very real possibilities of load loss connected with any rate increase. However, because BPA is committed to making planned payments to the Treasury, a portion of revenue risk must be mitigated through rate measures. Roberts/Metcalf, BPA, E-BPA-18, 3. It is for that reason that BPA has included a flexible adjustment (Cost Recovery Adjustment Clause) in its rates, which will not be implemented unless warranted by prolonged or severe adverse conditions. Roberts/Metcalf, BPA, E-BPA-18, 2.

PPC states that if BPA continues to include unreasonably large and purely subjectively determined amounts of "insurance" in its rates, BPA's customers will actively seek other suppliers of energy who do not insist on charging unreasonably for "insurance" along with the energy provided. Carr/Peters, PPC, E-PP-10A2, 4. PPC further asserts that short-run elasticities may prove in BPA's favor during the rate period, but are irrelevant to long-run decisions regarding firm power supply. Exceptions, PPC, R-PP-01, 4-5. Clark County PUD expressed similar concerns, stating that consumers will seek out alternate fuel sources if energy rates are high, and that this will seriously jeopardize BPA's ability to pay fixed costs, including the Treasury payment. Clark County PUD, WP-87-7504, 4.

PPC's position is inconsistent with its own conclusion that elasticities are low in the short run and high in the long run. Peters, PPC, E-PP-04, Attachment N. PPC's proposal would keep current rates lower than BPA's, but it would result in higher future rates, potentially much higher if BPA is unable to make its amortization payments. This risks serious long-term consequences of prolonged load loss. In fact, PPC has presented no evidence that BPA's expected rates in the future (the 1987 rate period and beyond) would be lower if BPA were to adopt the PPC risk mitigation package rather than BPA's proposal. Even if BPA's revenues turn out to be near or greater than forecast, so that the PPC proposal does not result in deferred Treasury payments, the additional revenue recovered under the BPA proposal will be used in the most prudent manner possible to reduce future rates.

Load elasticities for Priority Firm customers are considered in the analysis of potential revenue underrecoveries. Elasticity effects from fuel switching have been determined to be of a small enough magnitude that they do not jeopardize revenue recovery. Moorman/Schneider, BPA, E-BPA-52, 4. See Chapter II, Section D.

Decision

The inclusion of risk protection in the rates is appropriate, and is subject to the same elasticity effects as other rate factors. Risking much higher rates in the future for slightly lower rates now would not be wise given the relatively high long term elasticities. There is no evidence that inclusion of a lower level of risk protection in this rate filing will, under any scenario, reduce BPA's future rates.

D. Use of 1939 Water Conditions

Introduction

BPA used 1939 water conditions in the development of 1985 rates to estimate nonfirm revenues. This methodology offset expected revenue losses from nonfirm sales and other revenue sources and increased the likelihood that BPA would be able to make its projected payments to the U.S. Treasury in a timely manner. BPA, WP-85-FS-BPA-08, 147. Selection of this methodology was based on the results of the Revenue Uncertainty Analysis, which identified a potential revenue shortfall of $44 million for expected loads under average

water, and an overall potential revenue shortfall of $400 million. 1985 Rates ROD, WP-85-A-02, 18, 21. Without the protection provided by the 1939 water adjustment in the 1985 rate proposal (about $120 million), BPA's deferred borrowing at the end of FY 1985 would have been almost depleted by the end of FY 1987. 1985 Rates ROD, WP-85-A-02, 22.

Use of this methodology was further supported in the 1985 rate case by a request from FERC to anticipate sales and revenue underruns in the development of rates. 23 FERC, 61,378 (1983). 1985 Rates ROD, WP-85-A-02, 19. Accordingly, BPA used 1939 water to compensate for forecasted revenue underruns consistent with sound business principles. Id. FERC endorsed the use of 1939 water conditions in its order approving the 1985 rates. Docket No. EF85-2011-011 et al., (April 29, 1987), 6.

BPA proposes a continuation of the use of 1939 water conditions in the development of its rates. For the 1987 rates, the choice of water conditions affects the level of forecasted revenues for nonfirm energy and surplus firm power sales. Wedlund/Luttmer, BPA, E-BPA-14, 10. The use of 1939 water is included as part of BPA's risk management strategy, which also includes Investment Service Coverage and the Cost Recovery Adjustment Clause. Melton/Meyer, BPA, E-BPA-17, 5-6.

The use of 1939 water conditions in the development of rates is directly related to two major areas of risk faced by BPA: poor water conditions, and low nonfirm energy and surplus firm power revenues resulting from low gas and oil prices. Wedlund/Luttmer, BPA, E-BPA-46, 3. This methodology will also reduce the overall potential revenue shortfall determined in the Risk Assessment Analysis, and will improve the probability of timely payments to the U.S. Treasury. Melton/Meyer, BPA, E-BPA-17, 14.

Issue

Should 1939 water conditions be used as a risk mitigation measure?

Evaluation of Positions

BPA's proposal to continue the use of 1939 water conditions is based on a continued analysis of current water conditions and nonfirm energy and surplus firm power sales and revenues. The 1939 water adjustment is a total revenue adjustment to reflect the fact that actual revenues have consistently underrun forecasted revenues. Wedlund/Luttmer, BPA, E-BPA-46, 2. The use of 1939 water conditions is also a flexible risk mitigation measure that is directly responsive to changing water conditions and levels of surplus sales. The level of risk coverage provided by this assumption changes as the difference between revenues calculated using 1939 and average water conditions changes. This flexibility serves to lessen the revenue impact of uncertainties in the modeling of surplus sales, e.g., Market Expansion rate sales to the Pacific Southwest.

APAC states that BPA has shown no relation between the choice of 1939 water conditions and the need for risk mitigation. APAC states that it is

unlawful for BPA to generate contingency funds to guard against periodic nonfirm revenue shortfalls. Initial Brief, APAC, B-PA-01, 10-12. The legality of the 1939 water adjustment was established in the 1985 rate case, and has been endorsed as appropriate by FERC. Docket No. EF85-2011-011 et al., (April 29, 1987), 6.

PGP states that the use of 1939 water will result in an overcollection of revenues each and every year, regardless of actual water conditions. Helgeson et al., PGP, E-PG-04, 14. However, the use of 1939 water conditions does not guarantee that BPA will exceed or even meet its repayment obligations; it simply increases the likelihood that those obligations will be met. Wedlund/Luttmer, BPA, E-BPA-46, 2. Certainly during FY 1986 and FY 1987 BPA fell far short of meeting its revenue projections after it used 1939 water conditions to forecast revenues from nonfirm sales. FS-BPA-06, Appendix B, Table B-4. There is no reason to conclude that the use of this same assumption in the current rate proposal will result in revenue overrecovery.

PPC asserts that BPA should not use 1939 water. PPC claims that the use of other than average water has nothing to do with risk mitigation, and causes unnecessary controversy regarding water condition assumptions. Carr/Peters, PPC, E-PP-10A2, 1-2. PPC recommends an alternative risk mitigation package that does not include the use of 1939 water. Carr/Peters, PPC, E-PP-10A2, 9. PPC disagrees with the use of 1939 water for two reasons: (1) assessing risk should begin with the expected case, which is average water, and (2) 1939 water itself introduces unnecessary confusion into the process of calculating rates. Initial Brief, PPC, B-PP-01, 9. PPC also states that the expected base case nonfirm energy and surplus firm power revenues should be based on the water conditions which are most likely to occur. Exceptions, PPC, R-PP-01, 9.

BPA does not agree with the PPC assertion that the 1939 water assumption has nothing to do with risk mitigation. The 1939 water assumption is a total revenue adjustment to address the problem that actual revenues have consistently underrun forecasted revenues. Wedlund/Luttmer, BPA, E-BPA-46, 2. Furthermore, the 1939 water assumption is directly related to major areas of risk that have been identified in the Risk Assessment Analysis: potential revenue underrecovery associated with poor water conditions, and additional risk associated with lower than forecasted gas and oil prices. Id., 3. When the difference between average water and 1939 water changes, clearly the risk of assuming average water changes in the same direction. Therefore the 1939 water assumption automatically adjusts the risk protection when the level of risk changes. Contrary to the PPC's assertion, the 1939 assumption reduces controversy associated with the water assumption. A change in assumption is likely to affect revenues under average water much more than revenues under 1939 water (the issue in this rate case over the forecast of Market Expansion sales is a good example).

PPC's assertion that the use of 1939 water causes confusion is incorrect. This risk mitigation measure is calculated in the Nonfirm Revenue Analysis Program (NFRAP), and is specifically labeled for ease of location in the documentation for the rate case. While the NFRAP is complex, its use is clearly warranted. All parties have access to the necessary programs to

duplicate this adjustment, and many parties (including PPC) have availed themselves of this opportunity. Additionally, this measure was used in the 1985 rate proposal and was fully explained and justified both then and now.

WPAG also recommends that BPA eliminate the 1939 water assumption. WPAG characterizes the 1939 water adjustment as an under-estimation of nonfirm revenues. McGary et al., WPAG, E-WA-02, 26. WPAG further asserts that the use of the 1939 water assumption is "a departure from long established BPA rate practice and injects into the case complicated modeling and duplicative work for BPA staff and the parties." Id., 27.

WPAG's statement that the 1939 water adjustment constitutes an under-estimation of revenues is incorrect. In fact, current water conditions are worse than the 1939 water condition. Wedlund/Luttmer, BPA, E-BPA-46, 4. WPAG's argument that the 1939 water assumption departs from long established rate practice ignores the fact that this same assumption was included in the 1985 rates.

The use of 1939 water conditions in the development of rates will improve the likelihood that BPA will make its planned payments to the Treasury, but will not necessarily lead to the overcollection of revenues. Melton/Meyer, BPA, E-BPA-17, 14. The Cost Recovery Adjustment Clause is designed to reduce rates to specific customers if funds from operations in FY 1988 are substantially above planned levels. See Section F. These planned funds from operations are based on revenues under 1939 water conditions. Melton/Meyer, BPA, E-BPA-17, 15.

Decision

The 1939 water conditions are used to estimate expected revenues from nonfirm energy and surplus firm power sales. The use of the 1939 water assumption is an appropriate risk mitigation measure. There is no evidence that the use of 1939 water conditions will result in revenue overrecovery. This assumption addresses risk faced by BPA from uncertain water conditions and low gas and oil prices. It is a conservative approach consistent with the evidence presented that will allow BPA more certainty in recovering its revenue requirement.

E. Investment Service Coverage

Introduction

In the 1983 rate proposal, BPA included a capital investment "revenue financing" component in determining the FCRPS revenue requirement. 1983 Rates ROD, WP-83-A-02, 74-75. This measure was adopted to help assure payments to the U.S. Treasury and to improve BPA's fiscal integrity. Id. In the 1985 rate proposal, BPA included a component with similar purpose. This component was referred to as "Investment Service Coverage" (ISC). 1985 Rates ROD, WP-85-A-02, 59-66. Similar to the revenue financing component included in the 1983 rate case, ISC was included in the 1985 rate proposal to increase the likelihood that payments to the U.S. Treasury could be made on a timely basis

and to protect and improve BPA's fiscal condition. Id. In its order approving 1985 rates, FERC noted that BPA's inclusion of ISC is appropriate. United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis and Terminating Dockets, Docket No. EF85-2011-011 et al., (April 29, 1987), Mimeo at 6. BPA has continued the use of ISC in determining revenue requirements for FY 1988 and 1989 in its 1987 rate proposal. The level of proposed ISC is determined based on a target net interest coverage ratio. The interest coverage ratio provides a standard utility industry measure of ability to meet interest payments on long-term obligations, over and above all other operating expenses.

Issue 1

Should Investment Service Coverage (ISC) be included in determining FY 1988 and 1989 revenue requirements?

Evaluation of Positions

BPA includes ISC in determining FY 1988 and 1989 revenue requirements. Roberts, BPA, E-BPA-15, 46-67; E-BPA-35, 4-11. BPA includes ISC for two primary purposes. First, ISC provides added assurance that BPA will be able to meet its planned payments to the U.S. Treasury in FYs 1988 and 1989. Roberts, BPA, E-BPA-15, 47. ISC is a key component of BPA's overall risk management strategy and demonstrates BPA's commitment to meet its obligations to the U.S. Treasury on a timely basis. Id., 47, 58; Melton/Meyer, BPA, E-BPA-17, 8. The target level of net interest coverage and the associated level of ISC were determined within the context of BPA's overall proposed risk management strategy. Id. See Section C. 3., Issue 1.

Second, ISC is included to achieve a target net interest coverage ratio of 1.10 in FY 1988 and 1989. Roberts, BPA, E-BPA-15, 58-59. BPA reviewed industry practices and found that the interest coverage ratio is a standard measure used to assess an organization's ability to meet its interest payment obligations. The interest coverage ratio explicitly highlights the ability to cover interest costs over and above all operating expenses. Roberts, BPA, E-BPA-15, 50. If ISC is realized, BPA will recover all of its costs and realize a small improvement in its negative accumulated net revenue position, which at the end of FY 1987 was projected in supplemental testimony to be negative $452 million. Roberts, BPA, E-BPA-35, 5, 59. Final analyses indicate that BPA's accumulated net revenue position at the end of FY 1987 will be negative $560 million. FS-BPA-01A, Chapter 6.

Some parties object to BPA's effort to improve its financial condition through inclusion of ISC based on a target net interest coverage ratio. PGP objects to BPA's justification of ISC on the basis of a target net interest coverage ratio. Winterfeld et al., PGP, E-PG-03, 18. PGP argues that the justification for interest coverage requirements for other utility systems is not applicable to BPA. Id.; Exceptions, PGP, R-PG-01, 6. PGP further claims that "there is no benefit or obligation to improve BPA's financial statement or demonstrate its commitment to the Treasury." Winterfeld et al., PGP, E-PG-03, 15. APAC states that "BPA has no need for coverage either as part of

its borrowing terms or as a means to reduce its overall cost of capital." Wolverton, APAC, E-PA-01, 4; Initial Brief, APAC, B-PA-01, 13. PPC also objects to BPA's justification of ISC on the basis of a target net interest coverage ratio and asserts that BPA's comparisons to interest coverage standards within the utility industry are not valid. Carr/Peters, PPC, E-PP-03, 6; Exceptions, PPC, R-PP-01, 6. Further, PPC and APAC object to BPA's intent to ameliorate its negative accumulated net revenue position, and assert that the negative level is not relevant due to the fact that it is a result of the restatement of BPA's financial statements in FY 1985. Id., 7; Wolverton/Drummond, APAC/PPC, E-PA/PP-02, 6.

BPA reviewed the interest coverage practices and standards of the electric utility industry not to determine what specific level is necessarily appropriate for BPA, but to establish that the interest coverage ratio is used as a standard measure of an organization's financial strength. In fact, the most significant observation BPA made from review of industry standards is the importance of the level of interest coverage as a consideration of the prudence of incurring additional debt with respect to the ability to service that debt. Roberts, BPA, E-BPA-15, 63. BPA finances virtually all of its capital programs through issuance of long-term obligations, either appropriations for Corps and Bureau investment, or bonds issued to the U.S. Treasury for BPA construction and conservation. Id., 63-64. Given BPA's statutory responsibility to apply sound business principles in determining its required revenue level, it is prudent to consider BPA's ability to make interest payments on its long-term obligations, just as the rest of the utility industry does. Id., 64.

Lenders exact certain coverage or "times interest earned ratio" (TIER) requirements in order to provide an assurance that the utility will be able to meet its financial obligations, including those due the lender. Roberts, BPA, E-BPA-15, 59-64. BPA analogously must safeguard its financial obligations due to the statutory requirement that its rates be sufficient to "assure" repayment of the Federal investment in the FCRPS after meeting all other costs. 16 USC §839e (a)(2)(A). The fact that BPA is not expressly required by the U.S. Treasury to maintain a specific level of interest coverage does not preclude BPA from engaging in the sound business practice of imposing such a requirement upon itself as a means of assuring repayment and improving the fiscal integrity of the agency in order to secure a strong financing capability. Roberts, BPA, E-BPA-15, 64; Carr/Peters, PPC, TR 2604-2611.

Parties have noted that BPA's negative accumulated net revenue position is due to BPA's restatement of depreciation expense from the compound interest method to the straight-line method (in FY 1985) and the write-off of prior period WNP-2 net billed prepaid advances (in FY 1984). Winterfeld et al., PGP, E-PG-03, 16; Carr/Peters, PPC, E-PP-03, 7; Exceptions, WPAG, B-WA-02, 14-15. BPA made this change in its FY 1985 financial statements in order to conform with Generally Accepted Accounting Principles (GAAP). Carr, PPC, TR 2582. Without such a change, BPA would have not been able to represent that its financial statements fairly reflect BPA's financial condition in accordance with GAAP. As restated in accordance with GAAP, accumulated net revenues are negative $373 million (as of the end of FY 1986), indicating that liabilities exceed assets by $373 million. Roberts, BPA, E-BPA-15, 48, 59.

Based on BPA's final studies, this level is expected to deteriorate further to negative $560 million by the end of FY 1987. FS-BPA-01A, Chapter 6. BPA is required by law to establish rates which will generate revenues to recover all costs and expenses incurred by the Administrator. Roberts, BPA, E-BPA-35, 48-49; 16 USC §839e (a)(2)(A). A negative accumulated net revenue position is evidence that those costs have not been recovered. Roberts, BPA, E-BPA-15, 48-49. Continuation of this situation without corrective measures would not reflect adherence to sound business principles. Id., 49. Prudent action to secure a strong financing capability consistent with the lowest rates possible requires that BPA take steps to improve its financial position. Id. By planning for a target level of net interest coverage, BPA is taking the appropriate action to move toward making improvements in this large negative accumulated net revenue position. Id.

PNGC supports BPA's goal to improve its financial position over time and states that "[t]here is good reason for BPA to seek an improved financial position over time. If costs and revenues occur as projected during 1988 and 1989, BPA's proposed Investment Service Coverage will improve BPA's balance of accumulated net revenues. Over time this will assure the U.S. Treasury and other potential lenders that BPA is financially sound." Waddington, PNGC, E-PN-03, 3.

While parties take issue with BPA's justification of ISC based on a target net interest coverage ratio, most parties generally support the concept of including some amount in determining BPA's revenue requirement to provide increased assurance of making timely payments to the U.S. Treasury. However, OPUC states that due to BPA's deferred borrowing capability, BPA should not use any ISC in determining revenue requirements. Hellman, OPUC, E-OP-01, 5-6. See also Section F. Issue 5.

WPAG states that ISC represents a "conventional means of providing a financial reserve to meet revenue fluctuations" and that it "is easy to identify and administer." McGary et al., WPAG, E-WA-02, 27. PNGC and PGP, however, object to WPAG's assertion that ISC provides BPA with a "conventional means of providing financial reserves." Helgeson/Waddington, PGP/PNGC, E-PG/PN-01, 12-13. As an alternative, PGP suggests that funds could be included in BPA's rates for "establishment of a permanent reserve for insuring payment of annual interest and scheduled amortization . . . ." Winterfeld et al., PGP, E-PG-03, 25. PPC recommends that if any ISC is included in revenue requirements that it be set aside with the specific goal of meeting scheduled amortization payments. Carr/Peters, PPC, E-PP-03, 3; Exceptions, PPC, R-PP-01, 7. PNGC supports PPC's position. Initial Brief, PNGC, B-PN-01, 9. Similarly, ICUA states that "BPA should be building reserves against future bad years and consolidating its fiscal integrity . . . " and also supports PPC's position. Initial Brief, ICUA, B-IU-01, 4. The DSIs generally support BPA's inclusion of ISC, but urge BPA "to design an equitable contingency adjustment clause" and rely upon ISC less in the future. Schoenbeck, DSI, E-DS-02, 5-6; Initial Brief, DSI, B-DS-01, 3-4; Oral Argument, DSI, TR 2838-2839, 2915-2917. See also Section F. The IOUs support inclusion of ISC and recommend higher levels than that proposed by BPA. Brattebo et al., IOU, E-IO-01, 13-15. See also Chapter VI, Issue 4. Thus, most parties

generally agree that some level of repayment protection should be included in determining revenue requirements.

Decision

ISC will be included in determining FY 1988 and 1989 revenue requirements in an effort to better assure timely payments to the U.S. Treasury and to improve BPA's fiscal integrity. Inclusion of ISC is a key component in BPA's overall risk management strategy as a measure which provides added assurance that BPA will make its planned payments to the U.S. Treasury on a timely basis. Further, inclusion of ISC will allow BPA to strengthen its financial position.

Issue 2

What level of ISC should be included in determining revenue requirements for FYs 1988 and 1989?

Evaluation of Positions

BPA initially proposed that $60 million of ISC be included in both FY 1988 and 1989 in determining FCRPS revenue requirements to achieve a target net interest coverage ratio of 1.10. Roberts, BPA, E-BPA-15, 58; E-BPA-35, 4. ISC of $60 million would provide additional assurance of BPA's ability to meet its payments to Treasury on a timely basis. In addition, ISC of $60 million, if realized, would allow BPA to strengthen its financial condition. Roberts, BPA, E-BPA-15, 48-49, 59.

In determining the appropriate target net interest coverage ratio and the associated level of ISC to include in proposed rates, BPA weighed a number of goals, including lowest possible rates, the short- and long-run financial health of the FCPRS, and timely payments to the U.S. Treasury. Melton/Meyer, BPA, E-BPA-17, 5. While the lowest rates possible might be perceived by some of BPA's customers as desirable, such a goal would consider only the immediate future. This position ignores sound business principles, which require that both short- and long-run considerations be taken into account. Id., 10. In an effort to reach a reasonable balance between establishing rates at the lowest possible level, assurance of cost recovery, and BPA's short- and long-range financial health, BPA proposed the target net interest coverage ratio of 1.10 and the corresponding $60 million in ISC required to achieve that target. The net target interest coverage ratio of 1.10 and the associated $60 million of ISC proposed by BPA, if realized, would result in modest improvements in the BPA's financial position. Roberts, BPA, E-BPA-15, 59. However, at this rate, it would take more than 10 years to eliminate BPA's negative accumulated net revenue position, provided all funds were realized as planned. Id.

Improvements in BPA's financial position are necessary to assure that BPA maintains a strong financing capability and to assure the lowest rate levels possible. In initial testimony, BPA explained that a net interest coverage ratio of up to 1.25 would be more desirable during the FY 1988-89 period not

only to better assure improvements in BPA's financial condition but also to better assure timely payments to the U.S. Treasury. Roberts, BPA, E-BPA-15, 58.

The majority of parties support inclusion of some ISC or a similar component in determining BPA's revenue requirement as a means to mitigate some portion of the risk faced by BPA. Most parties believe, however, that BPA's proposed level of ISC at $60 million is too high.

PGP recommends that BPA should "establish a segregated amortization reserve fund" and include amounts in revenue requirements of no more than $30 million per year as "required reserves." Helgeson et al., PGP, E-PG-04, 20-22. Similarly, PPC suggests that "[t]he level of ISC proposed by BPA is too high given the fragile state of the regional economy." Carr/Peters, PPC, E-PP-03, 3-4. In initial testimony, PPC suggested that $30 million should be included in FYs 1988 and 1989 and should be used to set up an account wherein monthly deposits would be made. Id., 28. See Section E. Issue 3. In surrebuttal, PPC proposed that $45 million in both FYs 1988 and 1989 be included for this purpose. Carr/Peters, PPC, E-PP-10A, 9. PNGC and ICUA support the $45 million level proposed by PPC. Initial Brief, PNGC, B-PN-01, 9; Initial Brief, ICUA, B-IU-01, 4.

APAC recommends that BPA reduce ISC by at least $35 million per year (Wolverton, APAC, E-PA-01, 6), which would result in $25 million in ISC in each year. However, during oral argument, APAC suggested that $30 million in ISC would be an appropriate level. Oral Argument, APAC, TR 2853. APAC continues to recommend reduced levels of ISC. Exceptions, APAC, R-PA-01, 8. Finally, OPUC suggests that no ISC should be included in determining FY 1988 and 1989 revenue requirements. Hellman, OPUC, E-OP-01, 15. Instead, BPA should rely on its balance of deferred borrowing capability. Id. See Section F, Issue 5.

The DSIs generally support BPA's proposed level of ISC, but urge that BPA design an "equitable" rate adjustment clause and rely less upon ISC in the future. Schoenbeck, DSI, E-DS-02, 5-6; Initial Brief, DSI, B-DS-01, 3-4; Oral Argument, DSI, TR 2838-2839, 2915-2917. WPAG supports a higher level of ISC than that proposed by BPA and recommends that $80 million be included in both FY 1988 and 1989. McGary et al., WPAG, E-WA-02, 27; Initial Brief, WPAG, B-WA-01, 14. The IOUs suggest that $60 million is too low in FY 1989 and should be increased to $120 million in FY 1989 and in each year through the 7(b)(2) rate test period to reflect unanticipated risks. Brattebo et al., IOU, E-IO-01, 14. This position was subsequently reiterated by PP&L and PGE. Initial Brief, PP&L/PGE, B-PL/GE-01, 18. See also Chapter VI, Issue 5.

BPA recognizes the tension between keeping initial rates as low as possible and assuring that costs are recovered. Melton/Meyer, BPA, E-BPA-17, 9-10. Numerous parties acknowledge that judgment is ultimately called for in ascertaining the appropriate level of protection against risk, and the trade-off between how much should be included in initial rate levels versus an after-the-fact rate adjustment. Initial Brief, APAC, B-PA-01, 14; Oral Argument, APAC, TR 2932; Initial Brief, PGP, B-PG-01, 33-34; Oral Argument, PGP, TR 2938; Oral Argument, WPAG, TR 2944; Initial Brief, PPC, B-PP-01, 12-13; Oral Argument, PPC, TR 2953. WPAG states that "[s]triking a proper

balance between these two objectives has never been more important for BPA and its customers . . . ." Initial Brief, WPAG, B-WA-01, 2. Positions diverge as to the amount by which initial rates should include repayment protection versus the level of risk which should be accommodated if and when adverse events actually occur. See also Section C. 3. Issue 2. However, while parties differ in opinion as to the precise level that should be accommodated in initial rate levels, nearly all agree that some amount should be included but that BPA's proposed level should be reduced. Helgeson et al., PGP, E-PG-04, 20-22; Carr/Peters, PPC, E-PP-03, 3-4, 28; Carr/Peters, PPC, E-PP-10A, 9; Initial Brief, PNGC, B-PN-01, 9; Initial Brief, ICUA, B-IU-01, 4; Wolverton, APAC, E-PA-01, 6; Initial Brief, APAC, B-PA-01, 12; Oral Argument, APAC, TR 2853; Exceptions, APAC, R-PA-01, 8.

Given that the level of protection provided by the 1939 water assumption has increased above the level estimated in BPA's initial proposal (Melton/Meyer, BPA, E-BPA-17, Attachment 1; Wedlund/Luttmer, BPA, E-BPA-46A2, Errata to page 3), a reduction in ISC can be accommodated to reduce pressure on the initial rate increase without necessarily or unreasonably increasing BPA's repayment risk.

Decision

In light of the concerns expressed by the various parties regarding the increase in rate levels in the FY 1988-89 rate period, BPA will reduce its level of ISC to $39.3 million in FY 1988 and $49.8 million in FY 1989, which results in a reduction of $30.9 million over the FY 1988-89 period. These revised levels of ISC correspond to a net interest coverage ratio of 1.08 over the FY 1988-1989 rate period, reduced from the rate period target ratio of 1.10. Potential improvements in financial position as well as the level of repayment protection provided through ISC will be reduced in response to concerns that the proposed level of ISC at $60 million would cause excessive upward pressure on the initial rate increase for the FY 1988-89 rate period.

Issue 3

Should BPA establish and maintain a reserve fund?

Evaluation of Positions

BPA proposes that if funds provided through inclusion of ISC are realized, the Administrator will have the discretion to apply the funds in one or more of the following ways. First, the funds could be maintained on a temporary basis in cash balances which earn interest income; second, the funds could be used to finance portions of capital additions, thereby reducing the level of long-term borrowing and increasing BPA's deferred borrowing capability; third, the funds could be used to make additional amortization payments on outstanding ong-term obligations. Roberts, BPA, E-BPA-15, 66-67; E-BPA-35, 9. This flexibility allows BPA to apply funds in the most prudent manner and to minimize costs to ratepayers. Roberts, BPA, E-BPA-15, 64-67.

BPA's noncash working capital needs, however, must be taken into account prior to determining the level of funds potentially available for application to those purposes. Roberts, BPA, E-BPA-35, 9. In the 1982, 1983, and 1985 rate proposals, BPA accounted for projected changes in noncash working capital balances by including the Cash Lag Adjustment in determining revenue requirements. 1982 Rates ROD, 43; 1983 Rates ROD, WP-83-A-02, 75-76; 1985 Rates ROD, WP-85-A-02, 67-70. However, in determining revenue requirements for FY 1988 and 1989, BPA did not include the Cash Lag Adjustment in determining revenue requirements. Roberts, BPA, E-BPA-15, 45; E-BPA-35, 7. Based upon final studies, BPA projects that over the FY 1988-89 period, increases in noncash working capital balances will total $64.5 million. FS-BPA-01A, Chapter 6. Thus, on an actual basis, if ISC is realized, such funds may be required in part to fund increases in noncash working capital balances. To that extent, some funds will not be available to increase cash reserves, reduce borrowing, or increase payments of amortization of long-term obligations over amounts planned. Roberts, BPA, E-BPA-35, 9-10; E-BPA-47, 12-13.

PPC agrees that BPA is "properly planning for increases in noncash working capital balances . . ." but argues that BPA's analysis of FY 1988-89 noncash working capital requirements is not complete and therefore "gives a skewed result." Carr/Peters, PPC, E-PP-03, 9. However, PPC fails to demonstrate that BPA's working capital analysis is not valid. Roberts, BPA, E-BPA-47, 16-17. PPC further states that changes in noncash working capital balances should be explicity included in determining BPA's revenue requirement. Exceptions, PPC, R-PP-01, 8. PGP implies that BPA has included costs of prior periods in determining its revenue requirement. Winterfeld et al., PGP, E-PG-03, 31-35. This is incorrect. The level of ISC was not determined on the basis of projected changes in noncash working capital. Roberts, BPA, E-BPA-47, 14-15. Moreover, even if BPA had included an adjustment for changes in working capital in determining its FY 1988 and 1989 revenue requirements, inclusion of such would not have been without support. In fact, in its order approving BPA's 1985 rates, FERC supported BPA's inclusion of the Cash Lag Adjustment in determining revenue requirements. United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis and Terminating Dockets, Docket No. EF85-2011-011 et al., (April 29, 1987), Mimeo at 5.

Some parties disagree with BPA on the extent to which BPA should retain flexibility in the use of its funds. PGP states, "[i]f BPA is going to collect additional money from customers on the basis of assuring Treasury payments, we want assurance that the money will be there for that purpose." Initial Brief, PGP, B-PG-01, 24. PPC expresses concern that BPA's proposed application(s) of ISC would allow BPA to "increase spending." Carr/Peters, PPC, E-PP-03, 8; Exceptions, PPC, R-PP-01, 8.

PGP proposes that BPA establish a reserve fund over a 5-year period in amounts commensurate with the level of ISC or similar components used in determining revenue requirements. Helgeson et al., PGP, E-PG-04, 20-23. PGP proposes that BPA establish a segregated amortization reserve fund with the U.S. Treasury for risk management purposes. The use of this fund would be limited to meeting Treasury obligations. Id., 20. The balance of the fund

would be built up and brought back to target levels through annual deposits. Annual contributions to the fund would be reflected in revenue requirements as required reserves. Id. Unused funds in this account would be carried over from year to year and adjusted at the beginning of each rate period to a level which would be determined "appropriate" in the respective rate case. Id., 20-21. If use of fund reserves were necessary during the rate period, balances would be restored to the target level over the following rate period(s). Similarly, if funds accrued in excess of target levels, wholesale rates would be commensurately reduced in the next rate period. Id., 21.

PPC proposes that if ISC or a similar component is included in determining revenue requirements, the funds should be targeted to repayment through establishment of a Treasury account, or use of an existing account. Carr/Peters PPC, E-PP-03, 28-29. PPC refers to this fund as the "Amortization Reserve Account" (ARA). Id., 28. BPA would make monthly payments to the ARA and would draw funds from the ARA only at year-end to make scheduled amortization and interest payments if its cash on hand is not sufficient to make these payments. Id., 29. Funds in the ARA would carry over from year to year if they were not drawn for purposes of making payments to the Treasury. Id. PPC's ARA proposal allows that if circumstances are such that costs other than amortization and interest cannot be met, the ARA could be used for those costs. However, PPC proposes that in this instance, the use of the funds would be scrutinized in an "abbreviated" 7(i) process. Id., 29-30. See also Section F., Issue 11.

PPC claims that the General Accounting Office (GAO) "recommends" a reserve fund approach in the GAO report entitled "Pricing Alternatives for Power Marketed by the Department of Energy." Initial Brief, PPC, B-PP-01, 13; Exceptions, PPC, R-PP-01, 10. The PPC has mischaracterized the GAO report. The report merely notes that one method of providing "cash flow flexibility" to Power Marketing Agencies to meet a fixed repayment schedule would be to develop a "contingency fund or a cash reserve through power revenues." Briefing Report to the Honorable Howard M. Metzenbaum, United States Senate, Federal Electric Power, Pricing Alternatives for Power Marketed by the Department of Energy, United States General Accounting Office, September 1986, GAO/RCED-86-186BR, 24. This alternative was one of the three alternatives noted in that report, none of which was recommended. In fact, the report clearly points out that no estimate was made of the "added costs of implementing the methods of improving cash-flow flexibility." Id. GAO's inclusion of a contingency or reserve fund as one of several alternatives is neither a recommendation nor an endorsement of the ARA proposed by PPC.

The parties' proposed "reserve fund" would impose severe restrictions on the Administrator's flexibility to apply funds in the most prudent manner. The parties have asserted that BPA's proposed applications of ISC do not provide a "reliable reserve." Helgeson/Waddington, PGP/PNGC, E-PG/PN-01, 12; Initial Brief, PGP, B-PG-01, 24; Exceptions, PGP, R-PG-01, 6; Exceptions, PPC, R-PP-01, 8-10. This position assumes that BPA's primary purpose of including ISC is to build up a cash reserve fund. This is not the case. Moreover, if BPA chose to apply the funds to increase cash balances, those cash balances would most certainly be available. Second, the parties themselves recognize BPA's deferred borrowing capability (as a result of revenue financing) as a

source of funds. Helgeson et al., PGP, E-PG-04, 17; Initial Brief, PGP, B-PG-01, 33; Carr/Peters, PPC, E-PP-03, 32-35; Waddington, PNGC, E-PN-03, 2-3; McGary et al., WPAG, E-WA-02, 23, 27-29; Initial Brief, WPAG, B-WA-01, 8; Hellman, OPUC, E-OP-01, 3-4. In fact, the existence of deferred borrowing has provided flexibility for BPA to manage funds. Melton/Meyer, BPA, E-BPA-17, 12. This flexibility has allowed BPA to accommodate serious FY 1986 and 1987 net shortfalls while meeting all of its obligations. Id.

Further, the parties ignore BPA's projected increases in FY 1988-89 working capital requirements and the fact that BPA has not included the Cash Lag Adjustment in determining revenue requirements. Roberts, BPA, E-BPA-15, 45-46; E-BPA-35, 7. BPA included the Cash Lag Adjustment in the 1982, 1983, and 1985 rate proposals. 1982 Rates ROD, 43; 1983 Rates ROD, WP-83-A-02, 75-76; 1985 Rates ROD, WP-85-A-02, 67-70. The fact that it is not included explicitly in determining FY 1988 and 1989 revenue requirements does not mean that no such working capital requirements exist. In fact, even if BPA faced no risk of underrecoveries, in the absence of the Cash Lag Adjustment, inclusion of ISC would be required to fund increases in noncash working capital balances in order to assure the adequacy of funds for meeting Treasury obligations. Roberts, BPA, E-BPA-15, 49.

With regard to funds which are available once noncash working capital requirements have been satisfied, BPA's prospective applications of remaining funds provide the flexibility necessary to prudently manage funds so as to minimize costs. A number of factors must be considered in the prudent application of such funds, including current interest rates, interest rates on outstanding obligations, and overall financial condition. Roberts, BPA, E-BPA-15, 66-67. The first potential application identified by BPA is to place the funds in cash balances. In this sense, the parties' proposed "reserve account" is no different than the cash balances which BPA currently maintains with the U.S. Treasury in an interest-bearing account. However, under the parties' proposal, BPA would be restricted in using those funds even if such funds were required simply to meet basic obligations of operation and maintenance expense and purchase power costs as set forth in DOE Order RA 6120.2. Carr/Peters, PPC, E-PP-03, 29-30. PPC disagrees that its ARA proposal would result in such a restriction on BPA's use of funds. Exceptions, PPC, R-PP-01, 8.

The second potential application of remaining funds proposed by BPA is to finance portions of capital additions, thereby reducing the level of long-term borrowing and increasing BPA's deferred borrowing capability. If funds are required at a later date, the borrowing for capital programs may be incurred at that time in order to provide required funds. This application of funds has proven to be a reliable reserve. Melton/Meyer, BPA, E-BPA-17, 12. PPC itself states that "sound business principles include prudent interest expense minimization wherever possible." Carr/Peters, PPC, E-PP-10A, 13. In recent years, the interest rate at which BPA borrows has been higher than the interest earned on cash balances. Greater interest savings were realized by deferring borrowing than would have been realized by increasing cash balances. Thus, application of funds in this manner does not result in "increased spending" as implied by PPC; it merely reflects basic principles of prudent cash management. To the contrary, if funds are available, prudent

funds management dictates that borrowing and the associated interest costs be deferred until borrowing is actually required. In addition, the Administrator is committed to minimizing growth in BPA's long-term obligations to the U.S. Treasury, keep costs low, continue the budget process and public scrutiny, and not use rate increases to unreasonably accumulate revenues. Melton/Meyer, BPA, E-BPA-17, 13.

Finally, BPA has suggested that the funds could be used to make additional amortization payments on outstanding long-term obligations. The parties' "reserve account" proposal could unduly restrict the Administrator's flexibility to make payments to the U.S. Treasury above the amounts scheduled.

Decision

BPA will not establish a special reserve fund which would restrict the Administrator's flexibility to use funds in the most prudent manner. BPA's proposed applications of ISC are fully consistent with BPA's responsibilities to meet its repayment obligations. If funds are realized as planned and noncash working capital requirements are met, BPA will apply the remaining funds in one or more of the following ways. First, the funds may be placed in BPA's interest-bearing account with the U.S. Treasury; second, the funds may be used to finance portions of capital additions, thereby reducing the level of long-term borrowing; third, the funds may be used to make additional amortization payments on outstanding long-term obligations. Regardless of how the funds are used, recovery of the ISC will serve to reduce the level of future rates from the levels that would be needed if the ISC were not realized.

F. Cost Recovery Adjustment Clause (CRAC)

Introduction

BPA's initial rate proposal introduced a CRAC as a component of its risk management strategy. The proposed CRAC was applied to PF-87 (Preference and Exchange), IP-87, VI-87, CF-87, and NR-87 firm power rate schedules. The clause was designed to allow adjustment of these rates, either upward or downward, in response to actual fiscal year financial performance as compared to rate case projections. As initially proposed, the clause would operate as long as 1987 rates were in effect.

As the CRAC was originally proposed, each fiscal year BPA would perform an evaluation comparing actual funds from operations to planned funds from operations. After each 12-month evaluation period, it would be determined whether an adjustment would be applied.

If the deviation between actual and planned funds from operations exceeded $60 million dollars, an adjustment would be applied over nine months in the following year, January 1 through September 30. The $60 million deviation was termed a "threshold" or "trigger" for the application of an adjustment. The 9-month period, January 1 through September 30, was called the adjustment period.

The amount of the adjustment would be calculated by subtracting $20 million from the deviation between planned and actual funds from operations. This was characterized as a "target" of $20 million above the original plan in the case of a downward rate adjustment or below the plan in the case of an upward rate adjustment.

The targeted amount would be divided by the forecasted revenues from applicable rates during the adjustment period to obtain a percentage. This percentage would be applied to adjust the demand and energy components of each applicable rate schedule, the irrigation discount, and the discount for quality of first quartile service under the IP-87 and VI-87 rate schedules. In the case of an upward adjustment the percentage would be limited to 10 percent as applied to each rate schedule; a downward adjustment would be limited only by the floor rate when applied to the IP-87 and VI-87 rate schedules.

Before implementation of any adjustment, customers would receive notice, and a public review process would be conducted to allow opportunity for comment on BPA's calculation of the adjustment.

On February 2, 1987, at a noticed meeting, BPA received the "Northwest Customers' Proposed Risk Management Package," endorsed by 9 customers and customer groups representing a wide spectrum of BPA's Northwest customers. The customers' proposal included provisions for a "contingent rate surcharge" similar in several ways to the CRAC, but conditioned on an abbreviated 7(i) process before implementation. Roberts/Metcalf, BPA, E-BPA-36, Attachment 1.

Although BPA did not adopt the customer proposal itself, in supplemental testimony BPA incorporated two aspects of the contingent rate surcharge in a revised CRAC proposal. BPA eliminated provisions for evaluation periods subsequent to September 30, 1988, and adjustment periods subsequent to September 30, 1989, and added provisions for a more extensive public review process than initially proposed. Roberts/Metcalf, BPA, E-BPA-36, 3-4. In addition, BPA eliminated the provision for a downward adjustment to the IP-87 and VI-87 rate schedules. Roberts/Metcalf, BPA, E-BPA-36, 4.

When parties filed their direct testimony, several customers submitted separate risk management proposals which resembled but differed in one or more ways from the Northwest Customer proposal. APAC, the DSIs, the IOUs, NIU, PGP, PNGC, PPC, and WPAG offer alterations to BPA's supplemental CRAC proposal. Areas of difference include: the notice provisions and public review process proposed for implementation; the measure upon which an adjustment would be based; the nature and length of the evaluation period; the length of the adjustment period; the threshold for triggering an adjustment and the targeted amount of an adjustment; the limitation on the magnitude of

an adjustment; the rate schedules subject to adjustment; and the application of the adjustment to the IP-87 and VI-87 rate schedules.

Issue 1

Should a CRAC be incorporated into BPA's 1987 wholesale power rates?

Evaluation of Positions

BPA proposes to incorporate a CRAC into certain 1987 wholesale power rate schedules to provide added assurance of cost recovery from current customers without substantially overrecovering costs during the rate period. Roberts/Metcalf, BPA, E-BPA-18, 2.

The DSIs support the adjustment clause concept, but urge that the design ensure equitability among customer classes. Schoenbeck, DSI, E-DS-02, 5-6. PGP objects to an adjustment clause not tied to specific cost items or sources of underrecovery. Helgeson et al., PGP, E-PG-04, 15. PNGC supports the adjustment clause in concept, providing that BPA collects no more than necessary to maintain BPA's current financial position. Waddington, PNGC, E-PN-03, 2-3. WPAG favors an adjustment clause that restores BPA's financial reserves if they are depleted in the first year. McGary et al., WPAG, E-WA-02, 30. PPC includes a surcharge/rebate provision in its risk mitigation proposal, conditioned on the conduct of an abbreviated section 7(i) hearing to examine both the need for an adjustment and its calculation. Carr/Peters, PPC, E-PP-03, 30. APAC proposes greater reliance on the CRAC in BPA's risk management strategy, and proposes changes in timing and design. Wolverton, APAC, E-PA-01, 6-8. NIU expresses concern with the precedent of an adjustment clause and with elements of BPA's proposed design. Lovelin, NIU, E-NI-03, 22.

Most parties generally express support for the concept of limiting the initial rate increase in FY 1988 by providing for an adjustment during the rate period under certain conditions. Disagreements with BPA and among customers pertain to the nature, design, and timing of the adjustment. Design revisions described below are intended to address concerns of equity among customer classes and to reduce the amount of collection in the case of a rate increase caused by the implementation of the clause.

Decision

A CRAC, revised as outlined below, is included in 1987 wholesale power rate schedules in order to provide added assurance of cost recovery from current customers without substantially overrecovering costs during the rate period.

Issue 2

To what rate schedules should the CRAC apply?

Evaluation of Positions

BPA proposes to apply the CRAC to the demand and energy components of the PF-87 (Preference and Exchange), IP-87, VI-87, CF-87, and NR-87 firm power rate schedules, to the irrigation discount, and to the discount for quality of first quartile service under the IP-87 and VI-87 rate schedules. Roberts/Metcalf, BPA, E-BPA-18, 7-8; BPA, E-BPA-06, B11, B19.

PPC and WPAG assert that the CRAC should apply to all rates. Carr/Peters, PPC, E-PP-03, 12-15; McGary et al., WPAG, E-WA-02, 31; Exceptions, WPAG, R-WA-01, 20-22; Exceptions, PPC, R-PP-02, 14-15. WPAG believes that "BPA should not exempt the Southwest export rates from the operation of the CRAC surcharge on the supposition that the market may not bear the increase." Exceptions, WPAG, R-WA-02, 21. PPC finds "no reason for purchasers of nonfirm energy and surplus firm power to escape cost responsibility if market conditions improve." Exceptions, PPC, R-PP-01, 15.

The NF-87 and SP-87 rate schedules, to which the CRAC would not apply, are marketing tools crucial to enhancing BPA's sales in highly competitive and volatile markets. Flexible prices are necessary to respond to market conditions. Roberts/Metcalf, BPA, E-BPA-18, 7. BPA has designed its NF and SP rate schedules to "adjust" to market conditions, with both downward and upward price flexibility. BPA believes that in this rate period, these rate schedules will be able to track market conditions such that if the market improves, as PPC suggests, then the surplus rate will "adjust", without need for a CRAC.

Applying an adjustment to these schedules would not change rates expected to apply to these sales or revenues expected to be generated. In the case of a rate increase, including forecasted revenues from these rates in the adjustment calculation would reduce the effectiveness of the clause in protecting against risk. No additional revenues would be expected from nonfirm and surplus firm sales after applying the CRAC, yet other rates would be increased less, proportionately, resulting in lower revenues than the adjustment is designed to collect. Neither would the CRAC apply to prices negotiated at the SL-87 rate. Contracts negotiated at the SL-87 rate would be for long-term transactions and would contain prices not subject to periodic adjustment.

WPAG urged that the CRAC be applied to wheeling rates to promote equity between transmission and generation functional cost allocations. McGary et al., WPAG, E-WA-02, 21. PGP objects to the lack of distinction between generation and transmission functions in the application of the CRAC, arguing that an adjustment may result in redistribution of costs among customer classes contrary to original allocations and rate directives of the Northwest Power Act. Helgeson et al., PGP, E-PG-04, 15-16.

BPA has not applied the proposed CRAC to wheeling rates. Wheeling transactions do not represent a major source of risk to BPA's revenue stability, nor do they represent a major component of transmission costs. The remaining transmission-associated revenues and costs are related to the power rates. Consequently, the perceived lack of distinction between generation and

transmission in the application of the CRAC would not materially redistribute costs among the rate classes.

NIU argues that because of current economic conditions irrigators cannot withstand any rate increase and recommends that irrigation loads be exempted from the CRAC. Lovelin, NIU, E-NI-03, 22. BPA has proposed that the CRAC apply directly to the irrigation discount to maintain the existing relationship between the rates of irrigators and those of other firm power customers. Roberts/Metcalf, BPA, E-BPA-18, 7-8. In addition, as discussed under Issue 4, the irrigation discount will be adjusted to account for disproportionate impacts on irrigators resulting from the 9-month adjustment period. Evidence presented by NIU supports irrigators' seasonality concerns, but does not substantiate the advisability of exempting irrigation loads entirely.

Decision

The CRAC applies to the demand and energy components of the PF-87 (preference and exchange), IP-87, VI-87, CF-87, and NR-87 firm power rate schedules, the irrigation discount, and the discount for quality of first quartile service under the IP-87 and VI-87 rate schedules.

Issue 3

What evaluation period should be considered in applying the CRAC?

Evaluation of Positions

BPA proposes a 12-month evaluation period based on actual audited FY 1988 financial results in order to capture an entire planning and operating cycle and to allow the evaluation to be based on data that have been scrutinized by an independent accounting firm. Roberts/Metcalf, BPA, E-BPA-18, 9.

PPC, PNGC, and the DSIs propose that a 12-month evaluation be conducted based on 9 months of actual data and 3 months of forecasted data in order that the adjustment can be applied over a full 12-month period. Schoenbeck, DSI, E-DS-03R, 18; Waddington, PNGC, E-PN-03, 12; Carr/Peters, PPC, E-PP-03, 37. The DSIs contend that 3 months' data can be readily projected and that the equity of implementing a 12-month adjustment outweighs the administrative burden of using projected data. Schoenbeck, DSI, E-DS-03R, 19. PNGC's proposal includes a preliminary adjustment based on forecasted data and a second "true-up" adjustment, if necessary, to reduce an increase after audited data become available. PNGC's proposed true-up would not add to an increase. Waddington, PNGC, E-PN-03, 12-14.

WPAG supports BPA's proposal, arguing that the use of forecasted fourth quarter data is not consistent with a formula rate approach. McGary et al., WPAG, E-WA-03, 32. WPAG also argues that under PNGC's true-up approach BPA would have an incentive to overestimate the increase needed in order to avoid any possible revenue shortfall. WPAG contends that this would lead to increased volatility in rates. McGary et al., WPAG, E-WA-03, 33-34. PPC does

not support a true-up but proposes correcting for actual results at the time of BPA's next general rate case. Carr/Peters, PPC, E-PP-03, 37.

A key feature of BPA's proposal is its reliance on actual audited financial results. This allows the CRAC evaluation to be straightforward and objective. PPC seems to believe, however, that since all rate cases rely on forecasts, it would be only logical that the CRAC would do so. Exceptions, PPC, R-PP-01, 16. This argument is specious. PPC knows that the CRAC is not a rate case and that a formula rate requires actual, not forecast, numbers. Furthermore, PPC's solution of a "simple adjustment" to the FY 1989 rate proceeding," id., misses the point of a CRAC. As stated by WPAG, the use of forecasts is inconsistent with BPA's formula rate approach. McGary et al., WPAG, E-WA-03, 32. Reliance on forecasted fourth quarter data would introduce an unwarranted degree of uncertainty and complexity. If forecasted data are used to determine the adjustment, such forecasts must be carefully prepared and thoroughly scrutinized, both within BPA and by customers and interested parties. This would add to the overall administrative burden of the clause. Issue 11 discusses the impracticality of conducting the processes that would be required in order to use a combination of actual and forecast data.

In addition, the issue of a second adjustment arises. A second adjustment would significantly increase the administrative burden on BPA and its customers and could lead to increased rate volatility. McGary et al., WPAG, E-WA-03, 33-34. Any attempted resolution of these issues would depart from the objectivity and administrative simplicity embodied in BPA's proposal.

Decision

The evaluation will be based on 12 months of actual data: actual FY 1988 financial results. This evaluation design retains the key feature of reliance on actual financial results that have been subject to audit by an independent accounting firm. Because any adjustment would be based solely on actual past underrecovery or overrecovery, this design avoids the need to institute an administratively burdensome forecast and review process. It also eliminates the issue of a possible second adjustment to correct for actual results.

Issue 4

Over what adjustment period should the CRAC apply?

Evaluation of Positions

BPA proposes a 9-month adjustment period, beginning January 1, 1989, and ending September 30, 1989. This allows 3 months between the end of the evaluation period and the beginning of the adjustment period for incorporation of audited results, issuance of notice, and conduct of a public review process. Roberts/Metcalf, BPA, E-BPA-18, 9.

The DSIs, APAC, PNGC, and PPC propose a 12-month adjustment period beginning October 1, 1988 and ending September 30, 1989. Schoenbeck, DSI, E-DS-03R, 18; Wolverton, APAC, E-PA-01, 7; Waddington, PNGC, E-PN-03, 12; Carr/Peters, PPC, E-PP-03, 37. As noted under Issue 3, PNGC also proposes an

initial adjustment implemented October 1, 1988, through December 31, 1988, followed by a second adjustment to "true up" forecasted data to actual audited results if such a true-up would lower customer rates. Waddington, PNGC, E-PN-03, 12-14.

Customers opposing the 9-month adjustment period argue that it would affect summer peaking and winter peaking utilities disproportionately. Waddington, PNGC, E-PN-03, 12; Lovelin, NIU, E-NI-03, 22; Schoenbeck, DSI, E-DS-03R, 18. Irrigators argue that in the case of a CRAC increase they would be especially disadvantaged since the irrigating season falls mostly within the proposed 9-month adjustment period (January 1, 1989 - September 30, 1989). Lovelin, NIU, E-NI-03, 22.

WPAG supports the 9-month adjustment period. McGary et al., WPAG, E-WA-02, 31. WPAG argues that there is no evidence of the extent of the disproportionality claimed by the irrigation customers. Exceptions, WPAG, R-WA-01, 22.

An alternative offered by APAC is to implement the CRAC over 9 months, but to correct the adjustment for seasonality. Wolverton, APAC, E-PA-01, 8. Although this approach might offer some advantages, it appears to be more complex to administer than is necessary to address parties' concerns. APAC proposes classifying the adjustment between capacity and energy, allocating the energy portion over 12 months for each applicable rate class, and then reassigning those amounts in October-December to the remaining winter months. Exceptions, APAC, R-PA-01, 2-4.

As discussed under Issues 3 and 11, FY 1988 will constitute the evaluation period, and the adjustment will be based on audited financial results. Preliminary actual FY 1988 data will not be available until late October 1988. On November 1, 1988 BPA will issue notice of the preliminary results of the evaluation and will begin to conduct the public review process discussed in Issue 11. In accordance with the public review process, the CRAC can be implemented no earlier than January 1, 1989. As urged by customers and proposed by BPA in supplemental testimony, the adjustment will terminate on September 30, 1989. As a result, a 12-month adjustment period is not practicable.

BPA acknowledges that customer groups may be affected unevenly by the CRAC due to seasonal differences in loads as a result of a 9-month adjustment. It was not BPA's intent to disadvantage any group of customers in designing the CRAC. Contrary to WPAG's claim, evidence presented by NIU supports seasonality concerns. PNGC endorses BPA's proposal to adjust the CRAC to irrigating utilities. Exceptions, R-PN-01, 7-8.

BPA has evaluated and confirmed a degree of disproportionate impact on irrigators due to seasonal patterns, although some seasonal effect may be measured any time rates are changed. Metcalf, BPA, TR 1881-1882. Because other objectives of the CRAC prevent BPA from implementing a 12-month adjustment, it is reasonable to propose an alternative method of addressing this issue that will mitigate the clearly adverse impact on the irrigation customers.

Decision

The adjustment period will begin January 1, 1989, and end September 30, 1989. Three months are required between the end of the evaluation period and the beginning of the adjustment period to allow time to assemble data and conduct a public review process prior to implementation. To alleviate the disproportionate impact on irrigation loads, the irrigation discount will be adjusted to expose the irrigation loads to approximately the same annual average rate increase as other loads exposed to the CRAC.

Issue 5

What measure of financial performance should be used to calculate an adjustment?

Evaluation of Positions

BPA proposes to perform an evaluation of FY 1988 financial performance by comparing planned funds from operations to actual funds from operations for the evaluation period. Roberts/Metcalf, BPA, E-BPA-18, 5-6. Funds from operations was chosen as an approximate measure of fund sources available to make cash amortization payments to the Treasury. Id.

PPC proposes comparing BPA's end of FY 1988 cash plus deferred borrowing balance to the balance of cash plus deferred borrowing at the end of FY 1987. Carr/Peters, PPC, E-PP-03, 12-14. Although this approach is generally consistent with the risk mitigation objectives of the clause, it does not address the issue of recovering current period costs from current customers. In addition, funds from operations is a more widely recognized financial measure. Funds from operations is audited and is less subject to BPA discretion than is BPA's exercise of deferred borrowing. PPC further argues that only revenue underruns, not cost overruns, should be considered, asserting that BPA's design provides no incentive for cost control. Carr/Peters, PPC, E-PP-03, 12-14. WUTC states that manipulation of cash accounts and increased expenditures appear possible under BPA's proposal. Initial Brief, WUTC, B-WU-01, 10.

The CRAC was designed to account for both revenue and cost deviations from plan, and BPA still faces risks that costs will exceed estimates. PPC's and WUTC's concern with cost control is addressed in Issues 7 and 8, which describe the elimination of the discontinuity between the CRAC triggers and targets.

WPAG proposes evaluating BPA's end of FY 1988 deferred (unused) borrowing balance and implementing an adjustment if the balance is $10 million or more below $140 million. McGary et al., WPAG, WA-02, 31. This approach, too, is generally consistent with the risk mitigation objectives of the clause, but inconsistent with cost recovery objectives and does not guarantee to account for both revenue and cost deviations from planned levels. Additionally, funds from operations is less subject to BPA's discretion than borrowing. As noted above, BPA's discretion over the measure chosen is a concern of some parties.

Ability to make Treasury payments is a central objective of the CRAC. An adjustment based on an evaluation of funds from operations best achieves this objective.

Decision

The evaluation of FY 1988 financial performance is made by comparing planned funds from operations to actual funds from operations for the valuation period. Ability to make Treasury payments and cost recovery are the central objectives of the CRAC. An adjustment based on an evaluation of funds from operations, which incorporates both revenues and costs, achieves these objectives.

Issue 6

Should a downward as well as an upward rate adjustment be provided for in the CRAC?

Evaluation of Positions

BPA proposed a symmetrical adjustment design that could result in downward as well as upward rate adjustments. Roberts/Metcalf, BPA, E-BPA-18, 3-4. The provision for an upward adjustment provides a measure of protection against cost underrecoveries, while a downward adjustment provision protects purchasers of BPA's firm power from the potential of providing revenues substantially in excess of BPA requirements. Id.

The DSIs propose that BPA retain additional funds in the case of an overrecovery, either by increasing the upper target to $60 million above planned funds from operations or by eliminating the downward rate adjustment entirely. Schoenbeck, DSI, E-DS-02, 5. PNGC and WPAG also argue against a downward adjustment, stating that in good years BPA should use funds to improve its financial position and to promote stable rates instead of adjusting rates downward. Waddington, PNGC, E-PN-03, 11; Initial Brief, PNGC, B-PN-01, 11; McGary et al., WPAG, E-WA-02, 31; Initial Brief, WPAG, B-WA-01, 15.

PPC and PGP support a design that includes provisions for both upward and downward adjustments. Carr/Peters, PPC, E-PP-03, 32; Helgeson et al., PGP, E-PG-04, 24. APAC advocates a higher threshold for a downward adjustment than for a surcharge. Wolverton, APAC, E-PA-01, 6.

The principle of protecting against large deviations from planned financial performance over the rate period is a central feature of the CRAC. There are risks inherent in setting rates too high as well as in setting rates too low. Portions of the Northwest economy can ill afford rate increases. Oral Argument, PPC, TR 2951. A rate increase that turns out to be greater than required could be unnecessarily harmful. PPC urges BPA to set rates as low as possible to avoid the consequences of overrecovery. These include risks that utilities might seek competitive supply alternatives and that

revenues collected in excess of requirements might lead to pressure for use of BPA funds outside the region. Oral Argument, PPC, TR 2951-2952.

An asymmetrical adjustment design, as proposed by APAC, can protect against the risks of both underrecoveries and overrecoveries while also incorporating customer recommendations to build reserves following a favorable year and to retain less revenue following an adverse year.

Decision

The CRAC provides for an asymmetrical adjustment, as described in Issues 7 and 8. The design includes provisions for both upward and downward adjustments, retaining the principles of protecting against large underrecoveries while protecting firm power customers from providing revenues substantially in excess of BPA requirements. However, the targets have been revised to incorporate the principle of recovering less revenue following an adverse year and retaining more revenue following a favorable operating year.

Issue 7

At what level of variance between planned and actual financial performance (trigger) should an adjustment be applied?

Evaluation of Positions

BPA initially proposed a trigger of $60 million variance between planned and actual funds from operations for a rate adjustment under the CRAC. Roberts/Metcalf, BPA, E-BPA-18, 10. An underrecovery of more than $60 million in planned funds from operations would result in insufficient funds from current operations to make planned Treasury payments. Id. At this level BPA is able to make its planned amortization payments to the Treasury but does not fully recover rate period costs on a planned basis. Id.

As originally proposed by BPA, the upper and lower triggers were symmetrical. In their responses, several parties drew distinctions between the upper and lower trigger points. APAC advocates a higher threshold for a downward adjustment than for a surcharge. Wolverton, APAC, E-PA-01, 6. WPAG and PNGC oppose any downward adjustment. McGary, WPAG, E-WA-02, 31; Waddington, PNGC, E-PN-03, 11. The DSIs would also support such a design. Schoenbeck, DSI, E-DS-02, 5.

PPC supports symmetrical upper and lower triggers of $60 million variance, provided that the amount of the adjustment is targeted to the same point. Carr/Peters, PPC, E-PP-03, 12-13. PNGC argues for a lower trigger tied to cost recovery, also recommending that the adjustment be targeted to the trigger point. Waddington, PNGC, E-PN-03, 8.

Parties argue for a "dollar for dollar" adjustment for deviations exceeding the trigger. Initial Brief, DSI, B-DS-01, 18; Initial Brief, PNGC, B-PN-01, 10. Many parties emphasize their concern with what they characterize as a discontinuity between the CRAC triggers and targets, discussed in

Issue 8. Brattebo et al., IOU, E-IO-03, 1-2; Wolverton, APAC, E-PA-01, 7-8; Carr/Peters, PPC, E-PP-03, 12-13. PNGC argues that such a discontinuity provides BPA with an incentive to manipulate cash accounts or to increase expenditures in order to influence the CRAC evaluation. Waddington, PNGC, E-PN-03, 4. This argument is based on two allegations of fact and the apparent assumption that BPA would wish to force the CRAC to trigger a rate increase or to avoid a rate decrease. PNGC first alleges that BPA's limited discretion in timing its expenses would allow such manipulation. Waddington, PNGC, E-PN-03, 4. Second, PNGC asserts that BPA's decisions to revenue finance capital programs would influence the amount of the adjustment. Id. These allegations represent misconceptions on the part of PNGC of BPA's accounting practices. However, BPA acknowledges that the appearance of vulnerability to manipulation in the CRAC design should be eliminated.

Decision

The design of the CRAC triggers has been revised in light of parties' concerns. As explained in the Draft ROD, the lower threshold (for a rate increase) under the CRAC is $45 million below planned funds from operations. The upper threshold (for a rate decrease) is $80 million above planned funds from operations. In revising design parameters BPA has adopted the principles supported by several parties of a lower rate increase following an adverse year and retention of additional funds following a favorable year. Additionally, under the revised design the discontinuity between trigger and target is eliminated.

Because ISC has been reduced to an average of $45 million per year, an underrecovery of more than $45 million in planned funds from operations would result in insufficient funds from current operations to make planned Treasury payments. The upper threshold of $80 million above planned funds from operations is approximately equivalent to the level of additional funds from operations that would be expected in a year under average water conditions.

These revisions make BPA's risk protection package consistent with General Principles numbers 3 and 4 introduced by the parties during oral arguments. Oral Argument, DSI, TR 2838-2839.

Issue 8

How should the amount or target of the adjustment be calculated?

Evaluation of Positions

BPA initially proposed to calculate the amount of the adjustment based on a target of $20 million below planned funds from operations in the case of a rate increase and $20 million above planned funds from operations for a rate decrease under the CRAC. Roberts/Metcalf, BPA, E-BPA-18, 10. If rates are adjusted upward by the CRAC and targeted to $20 million below planned funds from operations, the resulting targeted net revenues would be approximately $20 million. This level was chosen to improve the financial condition of the FCRPS by continuing to strive for positive net revenues through the mechanism

of the CRAC. Id. The upper target of $20 million above planned funds from operations was selected based on the principle of symmetry reflected in the initial CRAC design proposal.

Parties objected to BPA's target proposals on two grounds. First, as discussed in Issue 7, all parties who addressed this issue contend that the discontinuity between the CRAC triggers and targets should be eliminated. Wolverton, APAC, E-PA-01, 7-8; Schoenbeck, DSI, E-DS-02, 4; Brattebo et al., IOU, E-IO-03, 1-2; Waddington, PNGC, E-PN-03, 4; Carr/Peters, PPC, E-PP-03, 12-13.

Second, parties argue that the lower target of $20 million below planned funds from operations is inappropriately high. At this level, BPA planned to achieve approximately $20 million in net revenues through the mechanism of the CRAC. Several parties present positions supporting lower equivalent net revenue targets. The DSIs and PPC support a target of approximately negative $20 million net revenues. Schoenbeck, DSI, E-DS-02, 4; Carr/Peters, PPC, E-PP-03, 33-34. PNGC favors a target that translates into approximately zero net revenues. Waddington, PNGC, E-PN-03, 8-9. At the zero net revenue level, on a planned basis, BPA would fully cover FCRPS costs, but would not achieve positive net revenues. At a negative $20 million net revenue target, on a planned basis, BPA would cover its amortization requirements, but would not fully cover FCRPS costs associated with the evaluation period.

Decision

As noted under Issue 7, the design of the CRAC targets has been revised to adopt the principles of a lower rate increase following an adverse year, retention of additional funds following a favorable year, and elimination of the discontinuity between the triggers and targets.

The lower target (for a rate increase) under the CRAC is $45 million below planned funds from operations. The upper target (for a rate decrease) is $80 million above planned funds from operations. If revenues are realized as projected under average water conditions and planned expenses are incurred, BPA will retain the additional $80 million in net revenues to balance against the net revenue shortfall of approximately $45 million which will not be recouped under this design.

Issue 9

What percentage limit is appropriate on an upward rate adjustment?

Evaluation of Positions

BPA proposes a limit of 10 percent adjustment to any rate schedule subject to increase under the CRAC. Roberts/Metcalf, BPA, E-BPA-18, 10. A 10 percent increase to subject rate schedules represents approximately $121 million in revenue over the 9-month adjustment period. This figure has been revised from the $140 million revenues estimated in BPA's initial proposal. Id.

APAC proposes that BPA lower the amount of ISC by at least $35 million and increase reliance on the CRAC by the same amount. Wolverton, APAC, E-PA-01, 7. PGP's proposal includes an upper limit of 5 percent over a 12-month adjustment period, which PGP estimates to be equivalent to approximately $100 million. Helgeson et al., PGP, E-PG-04, 24. PGP states that the potential for a midterm increase of 10 percent would represent a major source of uncertainty for PGP's members. Helgeson et al., PGP, E-PG-04, 16. PPC supports an adjustment of up to $105 million, justified by PPC's probability analysis which is discussed in section B. The PPC proposal also assumes a 12-month adjustment period. Carr/Peters, PPC, E-PP-03, 12. WPAG urges an upper limit of $140 million. McGary et al., WPAG, E-WA-02, 31.

BPA's proposal represents a balance between measures that would mitigate risk through initial rate increases and the CRAC which responds to actual financial performance. As discussed in section E, initial coverage has been reduced. This places more reliance on the CRAC to achieve the objectives of the risk management strategy. Thus, a lower limit would be inappropriate.

An increase of more than 10 percent has been opposed by parties desiring to limit the exposure of utilities to midterm rate increases. The level of revenue expected from a 10 percent adjustment over 9 months differs little from levels supported by parties, although parties argue for a 12-month adjustment period.

Decision

Rate increases under the CRAC will be limited to a maximum 10 percent adjustment to any subject rate schedule over the 9-month adjustment period. Ten percent appears to represent a reasonable balance between achieving BPA's risk management goals and limiting the degree of uncertainty faced by BPA's customers.

Issue 10

How should the CRAC be applied to the IP-87 and VI-87 rate schedules?

Evaluation of Positions

In BPA's initial proposal the IP-87 and VI-87 rate schedules were subject to the CRAC, with the exception that an adjustment to these rates could not result in a rate lower than the floor rate determined according to section 7(c)(2) of the Northwest Power Act. Roberts/Metcalf, BPA, E-BPA-18, 11. In supplemental testimony, BPA revised the language of the CRAC to eliminate any downward adjustment applicable to the IP-87 and VI-87 rate schedules. Roberts/Metcalf, BPA, E-BPA-36, Attachment 3. This revision was made because the floor rate appeared to control both IP-87 and VI-87 rate levels, and thus any downward adjustment would be zero according to BPA's proposal. Roberts/Metcalf, BPA, E-BPA-36, 4. Also, it appeared that any difference between the floor rate and the "equitable rate" established through the IP-PF rate link would be minimal. Metcalf, BPA, TR 1862.

The DSIs take issue with BPA's proposal on several grounds and offer suggested language addressing the deficiencies they identify. The DSIs' alternative language provides for a two-step procedure. Schoenbeck, DSI, E-DS-02, 3. First, the CRAC would be applied to the margin-based or "equitable" rate established through the IP-PF link, producing a preliminary adjusted rate. Second, that adjusted rate would be compared to the floor rate. The final adjusted rate would be the higher of these two rates. Id. The DSIs state that their revision treats the DSIs fairly in the event of an upward adjustment while preserving the floor rate. Id.

The DSIs charge that the clause proposed by BPA is inequitable in that it allegedly shifts revenue collection from one customer group to another. Under the BPA proposal, because of the floor rate, the DSIs claim that they cannot receive the full benefit of BPA's cost reduction, yet the CRAC is applied to the floor rate. Schoenbeck, DSI, E-DS-02, 2. Thus the DSIs face the potential for a smaller share of benefits, while bearing a greater share of costs under the CRAC than they would bear under a general rate increase. Id. If BPA's risk management strategy had relied more heavily on ISC or a "contingency fund," they argue, revenue collection would have followed a pattern more like the DSI proposal than the BPA proposal. Id.

In support of their position that the CRAC should apply to the equitable rate as opposed to the floor rate, the DSIs make a number of arguments. The DSIs argue: (1) that application of the adjustment to the floor rate would result in a rate higher than either the equitable rate or the floor rate, thereby violating the ratesetting requirements of section 7(c) of the Northwest Power Act; (2) that any allocation of costs to the DSIs under section 7(g) of the Northwest Power Act may be made only indirectly through the PF rate due to legislative history and GCP section 8(j) of the DSIs' power sales contracts; (3) that in the 1985 rate case, the Administrator exempted the DSI rate from any refund or surcharge under the Supply System and Exchange Adjustment Clauses because the IP-85 rate was determined by the floor, thereby evidencing the Administrator's determination that rate adjustments may not legally apply to the higher of the floor or equitable rate; and (4) that since one of the risks guarded against by the risk management strategy is the event of lower than forecasted aluminum prices, applying the CRAC to the floor may be counterproductive. Initial Brief, DSI, B-DS-01, 14-17. In light of the subsequent discussion concerning the trade-offs inherent in BPA's risk management strategy, it is unnecessary to discuss these arguments of the DSIs.

On a policy basis, the DSIs argue that (1) a balancing clearly occurs in BPA's risk management strategy as to what is to be recovered through rates initially versus potentially through a mid-course adjustment; (2) allocation of costs initially affects the equitable rate, not the floor rate; and (3) if the CRAC is applied to the floor, the DSIs are penalized by any decision that weights cost recovery to the CRAC, at least insofar as the costs represent the initial differential between the equitable and floor rates. Initial Brief, DSI, B-DS-01, 17. PP&L and PGE support the DSIs' position. Initial Brief, PP&L/PGE, B-PL/GE-01, 35.

The parties almost universally agree that a judgmental trade-off is involved when it comes to how much risk protection should be built into the

initial level of the rates versus any mid-course adjustment. Initial Brief, APAC, B-PA-01, 14; Oral Argument, APAC, TR 2932; Initial Brief, PGP, B-PG-01, 33; Oral Argument, PGP, TR 2934; Initial Brief, WPAG, B-WA-01, 14; Oral Argument, WPAG, TR 2944; Initial Brief, PPC, B-PP-01, 12-13. BPA agrees. Roberts, BPA, TR 1874-75; Metcalf, BPA, TR 1876. Insofar as practicable, BPA has sought to structure its risk management strategy so that its customers should be largely indifferent to the trade-off. Certain consequences, such as some apparent disproportional seasonal impact, cannot be reasonably avoided. The disproportional impact of applying the CRAC to the floor rate can easily and reasonably be avoided by applying the CRAC to the lower of the equitable rate or the floor rate, in the case of an upward adjustment.

PPC argues that whether the DSI rate is set by the floor or the equitable rate is irrelevant to subsequent adjustments, and that to adopt the DSI proposed language would be a form of retroactive ratemaking, in which previous decisions are used to determine new rates. Drummond, PPC, E-PP-07, 1-3; Exceptions, PPC, R-PP-01, 13. The relevance of the floor and equitable rates to application of the CRAC was established in connection with the discussion concerning disproportional impacts. PPC's second argument, concerning retroactive ratemaking, is specious since the CRAC operates prospectively to recover costs that BPA, as a self-financing agency, must at some time recover.

WPAG challenges the DSI proposal on several grounds. WPAG asserts that the DSI proposal would exempt the DSIs from paying their fair share in the case of an upward adjustment, noting that the DSIs are likely to have contributed to BPA's revenue shortfall in such a situation. McGary et al., WPAG, E-WA-03, 29-31. WPAG further argues that the DSI proposal has the effect of shifting costs to other customers and, to the extent that the clause has a percentage cap, reducing the total dollars BPA can collect. Id. The DSI proposal, WPAG claims, would be cumbersome to administer, because the portion assigned to the DSIs between the equitable rate and the floor rate would have to be identified and reallocated to non-DSI purchasers. Id. Finally, WPAG states that it is unnecessary, because of the variable rate, to exempt the DSIs from the CRAC to assure the DSIs' continued operations. Id.

WPAG's arguments rely on the assumption that the DSIs' "fair share" is based on the floor rate. The DSIs present convincing arguments that their "fair share" is more appropriately based on the IP-PF rate link. Oral Argument, DSI, TR 3054-3057. The DSI proposal does not exempt the DSIs from the CRAC; rather, it more closely resembles the way industrial rates would be determined in the absence of a CRAC. In addition, the language proposed by he DSIs operates regardless of the relative position of the floor rate and the rate established through the IP-PF link. Finally, the cumbersome reallocation process described by WPAG is not required by the DSI proposal. Other less complex methods are available to revise the application of the clause.

Decision

The adjustment to the IP-87 and VI-87 rate schedules will be determined according to a two-step procedure. First, the CRAC formula will be applied to the margin-based or "equitable" rate established through the IP-PF rate link, producing a preliminary adjusted rate. Second, that adjusted rate will be

compared to the floor rate. The final adjusted rate will be the higher of these two rates. Since all rate adjustments are limited to a 10 percent increase, BPA's maximum risk protection will be lessened by the unrecoverable revenues corresponding to the difference between the equitable and floor rates.

Issue 11

What process is appropriate to implement the CRAC?

Evaluation of Positions

In its initial proposal BPA proposed a 45-day public notice and comment process to implement the CRAC. BPA, E-BPA-06, 55-56. Because the initial proposal contained a 9-month adjustment period, this 45-day process began on November 15, 1988, in order to make the adjusted rates effective from January 1, 1989 to October 1, 1989. Id. During this proposed process parties were to have the opportunity to comment on BPA's determinations with respect to the need for and the amount of an adjustment. Id. In response to the "Northwest Customers' Proposed Risk Management Package," presented at the February 2, 1987, noticed meeting, BPA filed supplemental testimony which clarified this 45-day process. Roberts/Metcalf, BPA, E-BPA-36, 3. Specifically, BPA submitted a revised General Rate Schedule Provision, Section III.C.5, which permitted the parties reasonable access to BPA financial data, round table discussions with BPA representatives to explore BPA's determinations and justifications, opportunity to submit written comments by December 15, 1988, and opportunity to present oral argument upon written request. Id., Attachment 2, 3-4.

A number of parties to the rate case argue that implementation of the CRAC requires BPA to conduct a section 7(i) hearing under the Northwest Power Act. Helgeson et al., PGP, E-PG-04, 24; Initial Brief, PGP, B-PG-01, 35; Exceptions, PGP, R-PG-01, 7 and 15; Waddington, PNGC, E-PN-03, 14; Initial Brief, PNGC, B-PN-01, 11; Carr/Peters, PPC, E-PP-03, 13; Initial Brief, PPC, B-PP-01, 14-15; Exceptions, PPC, R-PP-01, 11; McGary et al., WPAG, E-WA-02, 30; Initial Brief, WPAG, B-WA-01, 15; Exceptions, WPAG, R-WA-01, 17-18; Lauckhart, Puget, E-PS-03, 2; Initial Brief, Puget/MPC/WWP, B-PS/MP/WP-01, 7; Exceptions, Puget/MPC/WWP, R-PS/MP/WP-01, 18-20; Initial Brief, WUTC, B-WU-01, 9. Some parties state that a mid-course adjustment such as the CRAC is the same as establishing new rates under section 7(a)(2) of the Northwest Power Act. Initial Brief, WPAG, B-WA-01, 12; Initial Brief, Puget/MPC/WWP, B-PS/MP/WP-01, 7; Initial Brief, WUTC, B-WU-01, 9; Initial Brief, PPC, B-PP-01, 14-15. Under this argument such new rates would require approval by FERC in order to serve as a predicate for judicial review. Oral Argument, WPAG, TR 2863.

The DSIs argue that the CRAC is similar to BPA's previous automatic adjustment clauses, such as the Exchange and Supply System adjustment clauses, which have been approved by FERC. Oral Argument, DSI, TR 2864. As a formula rate, the DSIs continue, the CRAC is subject to review in the present 1987 rate proceeding, and is "perfectly legal." Id. Although WPAG claims that the Exchange and Supply System adjustments also required a section 7(i) hearing,

WPAG did not challenge those adjustments because of the "circumscribed nature and the limited effect of those adjustment clauses." Oral Argument, WPAG, TR 2914. A CRAC, WPAG argues, is a change in character and magnitude from these previous adjustments, and therefore requires no discretion as to the type of process afforded the customer. Id. Some IOUs also believe that the CRAC is not comparable to the Exchange and Supply System adjustments. Exceptions, Puget/MPC/WWP, R-PS/MP/WP-01, 19-20.

PP&L and PGE do not argue for a section 7(i) hearing and generally support the modifications BPA made in supplemental testimony to clarify the proposed public process to implement the CRAC. Initial Brief, PP&L/PGE, B-PL/GE-01, 53. Following the noticed meeting on February 2, 1987, PP&L had proposed a 90-day process with provisions for financial data access, round table discussions, and oral argument for good cause shown. PP&L, WP-87-M-39. The DSIs support PP&L's proposed process. Schoenbeck, DSI, E-DS-02, 3.

PP&L and PGE, however, dispute the length of a 45-day process, contending that "[a]t least 60 days are needed from the date of Bonneville's notice until the date the retail rates can become effective." Initial Brief, PP&L/PGE, B-PL/GE-01, 54. In PP&L's case, at least two weeks are required to prepare its six-state retail rate filings based on BPA's surcharge. Id. In the State of Oregon, PP&L argues, a minimum of 45 days must elapse between a utility's rate filing and the effective date of a rate order. Id.; Brattebo et al., E-IO-03, 2-3, Exhibit 1. PP&L thus requests BPA's accommodation on this issue. Oral Argument, PP&L, TR 2973. Other IOUs, on the other hand, argue that any notice period shorter than 9 months violates section 8 of the General Contract Provisions of the Power Sales Contracts, which requires 9 months' notice in the Federal Register before a rate adjustment. Initial Brief, Puget/MPC/WWP, B-PS/MP/WP-01, 7-8. WUTC, although advocating a section 7(i) process, also supports a minimum of 60 days to allow the tracking of the adjustment at the retail level. Initial Brief, WUTC, B-WU-01, 9.

The CRAC is a formula rate adjustment. Its operation is similar to previous BPA rate adjustment clauses in that the formula compares actual costs and revenues to the costs and revenues forecast for the development of rates in order to derive a differential amount to be added or subtracted from applicable rates. See Exchange and Supply System Adjustment Clauses, 1985 General Rate Schedule Provisions Section III.C.6 and 7, approved by FERC on a final basis, United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis And Terminating Dockets, Docket No. EF85-2011-011 et al. (April 29, 1987). In the case of the CRAC, the Cost Recovery Variance (CRV) is determined by subtracting the FY 1988 planned funds from operations (PFFO) from the actual funds from operations (AFFO) to be derived from independently audited BPA financial statements. See General Rate Schedule Provisions, Revised Section III.C.5, Roberts/Metcalf, BPA, E-BPA-36, Attachment 2. The 12-month evaluation period for the CRAC, see Issue 3, supra, assures a full fiscal year performance period within which to obtain the CRV from the audited AFFO and the PFFO.

As with all of the proposed rates to be filed with FERC on July 31, 1987, the CRAC formula adjustment will be reviewed by FERC for confirmation and

approval. The CRAC formula, as with previous adjustment formulae, has been subject to a section 7(i) hearing process, and another section 7(i) hearing on, and subsequent FERC review of, an application of the formula in 1989 is not necessary. See, e.g., U.S. Department of Energy, Bonneville Power Administration, 33 FERC paragraph 61,049 (1985). Legally, a section 7(i) hearing is not required. WPAG does not explain why, once FERC confirms and approves BPA's 1987 rate proposal, including the CRAC formula adjustment, WPAG would be unable to challenge the CRAC at that time. If WPAG's fear is that lack of a section 7(i) hearing to implement the CRAC will somehow deprive it of judicial review, WPAG's failure to articulate the basis for its fear leaves BPA nothing to which it can meaningfully respond.

Moreover, if BPA understands WPAG's vague assertions correctly, requiring a hearing for the purpose of providing a basis on which to predicate judicial review appears counterintuitive. Assuming that a legal challenge to implementation of the CRAC were appropriate, the matter would only be ripe once FERC issued its final approval of the 1987 rate proposal, including the CRAC formula adjustment. Judicial review of BPA's rates is appropriate only after final confirmation and approval by FERC. 16 USC §839f(e)(1)(G); Atlantic Richfield, et al. v. BPA, Docket Nos. 83-7971, 83-7981, 85-7473, and 85-7488, slip op. at 8-9 (9th Cir. June 5, 1987), citing City of Seattle v. Johnson, Docket No. 83-7947 (9th Cir. April 1, 1987); U.S. Department of Energy, Bonneville Power Administration, Order Clarifying Previous Order, Denying Stay, and Denying Rehearing, Docket No. EF84-2011-006, et al. 28 FERC paragraph 61,078, 61,147 (July 23, 1984). It is likely such approval would occur after implementation of the CRAC. If a section 7(i) hearing were required to implement the CRAC, WPAG would then have to await FERC approval prior to seeking judicial review. It does not appear that the further delay would promote WPAG's goal of speedy judicial review.

Practical exigencies argue against conduct of a section 7(i) hearing. In order for the CRAC to operate most efficiently as a formula adjustment, a full twelve months of BPA financial performance and enough time to evaluate the performance and obtain audited actual numbers are required. As the CRAC is currently proposed, only 3 months are available to BPA to obtain and evaluate the audited numbers. FERC requires a full 60 days for its review process alone. 18 CFR §300.10(a)(3)(ii). A one-month period to obtain and evaluate audited numbers and to meet with BPA's customers regarding implementation of the CRAC is not workable and would be of little value. Contrary to PPC's proposed shortened 7(i) process, Exceptions, PPC, R-PP-01, 12, the loss of 2 months in a 3-month implementation period, awaiting FERC approval, is unacceptable and unnecessary given the formula nature of the CRAC. Filing requirements of FERC, such as Statements A-F, impose an additional burden on the agency as well.

PPC believes that use of the section 7(i) process gives BPA more flexibility than a fixed formula, arguing that BPA can "impose an adjustment tailored to BPA's needs as opposed to the automatic features of CRAC." Initial Brief, PPC, B-PP-01, 18; see also Oral Argument, PPC, TR 2952. PPC offers a schedule for an abbreviated section 7(i) hearing. Carr/Peters, PPC, E-PP-03, Attachment M. Under this schedule PPC advocates customer meetings in June 1988, with a 30-day hearing process commencing on July 1, 1988, and

ending with the FERC filing on August 1, 1988. Id. FERC approval would follow 60 days later on October 1, 1988. Id.

Issue 3 discusses the appropriate evaluation period for the CRAC; the appropriate evaluation period is the 12 months of FY 1988. That decision along with the decision of Issue 4, the adjustment period for the CRAC, require that two quarters of estimated data for FY 1988 cannot be used for evaluating the CRAC, and that the CRAC should properly be applied for the 9 months January 1989 through September 1989.

Beyond the decisions of evaluation period and adjustment period there are reasons why a section 7(i) process cannot be conducted in the 3 months following FY 1988. FY 1988 data cannot be made available immediately following the end of the fiscal year and estimates of the fiscal year data will not be available for evaluation until about November 1, 1988. Additionally, the audited data necessary for filing with the FERC assuredly will not be available by November 1, 1988, the approximate time required for filing with the FERC, 60 days before implementation on January 1, 1989. Furthermore, additional filing requirements such as Statements A-F and updated Repayment Studies could not be prepared in the time available before the 60-day filing period.

The formula adjustment based on audited full-year financial statements was chosen in order to minimize controversy in application of the CRAC and make the adjustment automatic. During this rate process parties have taken full advantage of the opportunity to comment on methodology and formulae of the CRAC. Given the automatic nature of the adjustment, a separate section 7(i) process and FERC review of results that rely solely on BPA's audited financial statements simply are unnecessary and counterproductive. PPC's suggestion of conducting an abbreviated section 7(i) process seems inconsistent in context of PPC's own arguments that their members have been "victims" of 7(i) hearings conducted in less than two weeks. Exceptions, PPL, R-PP-01, 12.

WPAG believes that FERC would waive the 60-day review period for CRAC implementation. Exceptions, WPAG, R-WA-01, 18-19. Yet in support of this idea, WPAG declares that a FERC waiver would be especially simple since the CRAC is a "straightforward adjustment based on easily determinable sums involving no forecast or allocation questions." Id, 19. WPAG understands correctly that the CRAC is an objective formula, which is precisely why BPA believes that no section 7(i) hearing is required.

Even if the 60-day FERC filing requirement were the only impediment to conducting a section 7(i) process, BPA has no reason to believe that FERC would view favorably a BPA request for waiver of the 60-day requirement. Prior BPA 7(i) processes or other actions that resembled 7(i) processes in which BPA received a waiver of the 60-day requirement were merely modifications of individual rate schedules that relied on records already filed with the FERC. By conducting a section 7(i) process on this otherwise automatic adjustment, a record of controversy would be created where none otherwise would exist. With a new record the FERC would not be expected to waive the 60-day filing requirement if for no other reason because of the widespread application of the CRAC.

The parties who advocate a section 7(i) hearing before implementation of the CRAC are not persuasive. Some IOUs claim that by virtue of providing the customers public involvement on CRAC's implementation, BPA admits that the CRAC is a "general substitute for a rate case." Exceptions, Puget/MPC/WWP, R-PS/MP/WP-01, 19-20. These IOUs do not understand that the public involvement BPA provides on the implementation of the CRAC is not a general rate case but rather an opportunity for the customers to review BPA's implementation of the formula. It is an opportunity to assure the customers that the formula is implemented as intended. PPC considers BPA's CRAC public involvement a "beneficial modification" to the proposal, and then advocates a section 7(i) hearing. Exceptions, PPC, R-PP-01, 10-11. Be that as it may, PPC argues that a section 7(i) hearing cannot be disregarded by BPA because "[i]t is a procedural safeguard to protect the public against unfounded and arbitrary decisions by the agency." Id., 12. BPA has designed the CRAC to avoid the very arbitrariness feared by the PPC. With audited actual numbers the CRAC formula will operate objectively and fairly.

BPA can accommodate the PP&L, PGE, and WUTC request for 60-days' notice of any CRAC implementation. Although 60 days before the effective date of any adjustment is only 30 days after the close of Fiscal Year 1988, BPA would be able to release preliminary unaudited AFFO results by November 1, 1988, to begin the public review process. BPA intends to craft a 60-day public process which provides its customers the safeguards similar to those offered by the statutory section 7(i) process.

Some parties also claim that the lack of FERC approval conflicts with the residential exchange subsidy contracts regarding the right to deem an average system cost equal to the PF rate after interim or final FERC approval of rates. Initial Brief, WPAG, B-WA-01, 12-13; Lauckhart, Puget, E-PS-03, 2-3; Initial Brief, Puget/MPC/WWP, B-PS/MP/WP-01, 8. The residential exchange subsidy contracts provide that the exchanging utility may elect to deem its average system cost equal to the PF rate following interim or final confirmation and approval by FERC. The utility must make the election within 25 working days of this FERC action. In spite of some IOU's claim that BPA's permission is not adequate assurance, Exceptions, Puget/MPC/WWP, R-PS/MP/WP-01, 21, BPA believes that permitting an exchanging utility to elect to deem its average system cost equal to the PF rate, as adjusted by CRAC, within 25 working days of the effective date of the CRAC fulfills the purpose and intent of the deeming provisions of the exchange contracts. Recission of this election will be treated in a similar manner.

Several IOUs also claim that the Power Sales Contracts are breached by lack of FERC approval. Initial Brief, Puget/MPC/WWP, B-PS/MP/WP-01, 7. BPA intends to publish a Federal Register notice of the 1988 CRAC adjustment in early 1988 in order to satisfy the concerns of these parties regarding nine-month notice of rate adjustments under the Power Sales Contracts.

Decision

A 60-day public process, commencing on November 1, 1988, and crafted to afford the customers involvement similar to a section 7(i) hearing, is appropriate to implement the CRAC.

Issue 12

Should the Administrator have discretion over whether or not to implement the CRAC?

Evaluation of Positions

As proposed by BPA, the CRAC provides for an automatic adjustment based on a formula which appears in the general rate schedule provisions. There is no provision for the Administrator to waive implementation of either a rate increase or decrease if the formula is applied and an adjustment is indicated. Roberts/Metcalf, BPA, E-BPA-18, 11.

The DSIs and PNGC state that the Administrator should have discretion to waive implementation of a rate increase in the case of a very small adjustment. Schoenbeck, DSI, E-DS-02, 5; Waddington, PNGC, E-PN-03, 11.

As discussed in Issues 7 and 8, virtually all parties support elimination of the discontinuity between the triggers and targets in the design of the CRAC, and BPA has adopted a revised design in response to parties' positions. Under the revised CRAC, an insignificant adjustment can theoretically result. If, in the case of a rate increase, the burden on BPA and its customers exceeds the value of projected additional revenues, it may be in the best interests of BPA and the region to waive the increase.

Decision

The Administrator may waive implementation of a rate increase under the CRAC.

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CHAPTER IV

REVENUE REQUIREMENT

A. Introduction

BPA is a self-financing power marketing agency within the United States Department of Energy. Rates for the sale of electric power and transmission services are BPA's only sources of revenue. See Central Lincoln PUD v. Johnson, 735 F.2d 1101, 1116 (9th Cir. 1984). These rates must produce revenues sufficient to assure repayment of all Federal investments in the Federal Columbia River Power System (FCRPS) over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C. §§832g and 839e(a). At the same time, BPA must set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. 16 U.S.C. §839e(a)(1). The Revenue Requirement Study determines the level of revenue required to recover all of BPA's expenses and obligations over the cost evaluation period, consistent with all of these statutory obligations. As ordered by the Federal Energy Regulatory Commission (FERC), separate revenue requirement determinations are made for the transmission and generation portions of the FCRPS. U.S. Department of Energy, Bonneville Power Administration, 26 FERC ¶61,096 (1984).

Over the period of time since 1974 when BPA became self-financing, the agency has continuously striven to become more financially responsible and businesslike in its operations. A major initiative in this regard was undertaken by the previous Administrator, Peter Johnson. Drawing on his highly successful background in private industry, he believed that it was very important that BPA identify and report its costs and revenues using generally accepted accounting principles. The major benefits of this approach are enhanced internal management of BPA financial operations, as well as clearer, more objective, and more consistent reporting of financial information to BPA's customers, creditors, Congress, and the business community in general.

Shortly after BPA completed the 1985 rate case, this goal was realized. In the 1985 Annual Report, BPA's independent auditor issued the opinion that the 1985 FCRPS Statements of Revenues and Expenses (Financial Statements) presented "fairly the financial position of the FCRPS . . . in conformity with generally accepted accounting principles."

In a further effort to promote consistency and clarity of BPA financial information, the format for presenting BPA's revenue requirement has been revised in the 1987 rate case to match more closely the presentation of revenues and expenses in BPA's financial statements. (See Revenue Requirement Study, E-BPA-01.) An additional purpose is to permit careful consideration of BPA's expected financial performance under the proposed rates. It is the Administrator's policy that it would be inconsistent with sound business principles to design rates with the expectation of incurring operating losses. Consequently, careful consideration is made of projected financial results as presented according to generally accepted accounting principles.

An expanded explanation of, and support for, this policy is contained in the discussion of Investment Service Coverage, Chapter III.

The outstanding revenue requirement issues fall into three general categories. The first category deals with the proper identification and matching of transmission costs with the specific segments of the Federal Columbia River Transmission System (FCRTS). The second category deals with the data and assumptions BPA employs when conducting repayment studies for the purpose of scheduling amortization and projecting interest expense. The third category concerns the correct identification and inclusion of costs in the total revenue requirement.

B. Segmentation

Issue

Is the total projected investment for the Southern Intertie correctly stated for this rate proposal?

Evaluation of Positions

PGE claims that BPA's projected improvements to the AC Intertie and the DC intertie terminals show $17,670,000 in investments that BPA's proposed rates will not recover. Initial Brief, PGE, B-GE-01, 5. PGE states that the investments for the Southern Intertie segment included in the Segmentation Study, BPA, E-BPA-02, 326-327, are approximately $17 million less than what PGE derives by adding BPA obligations for the Malin and Grizzly contracts to the estimated additions for Celilo Substation, the Dynamic Voltage Support (DVS) Facility, and the Fort Rock Capacitor Station that were included in the Ten Year Forecast. Kellerman, PGE, E-GE-01, 8-10. PGE further contends that these projects are part of the DC terminal upgrade scheduled for completion in FY 1989. Id.

The future plant investment in the Segmentation Study is based on the analysis of current individual work orders. For the rate period this information is more up-to-date and accurate than the earlier estimates used in the "Ten Year Forecast" (projected transmission additions for the period 1986-1995). Roberts, BPA, E-BPA-15, 4-15. In addition, the work order amounts have been escalated to the dollar value in the year of plant energization. BPA, E-BPA-02, 326-327.

Only the project identified as "Celilo Substation" is included in the DC terminal upgrade. Roberts, BPA, E-BPA-47, 25. The DVS Facility (at Malin) is not scheduled to be completed during the cost evaluation period. Id. The project identified as "Fort Rock Capacitor Station" is a part of the improvements to the AC Intertie System, not the DC terminal expansion. Id. It is scheduled to be placed in service in FY 1989 and is included in the total Southern Intertie rate period additions. Id.

Decision

The forecasted plant additions in the Segmentation Study were correctly stated for the Southern Intertie.

C. Repayment Studies

Issue 1

Should repayment studies schedule irrigation assistance payments in advance of final due dates?

Evaluation of Positions

The Bureau of Reclamation determines and provides to BPA the amount of irrigation assistance that is incorporated in the repayment studies. BPA, E-BPA-01A, 415. As in prior rate proposals, the repayment studies schedule and restrict irrigation assistance payments to their due dates as set forth by the Bureau. BPA, E-BPA-01, 60 and 67.

PGP suggests that the irrigation assistance payments should be included in repayment studies as investments carrying a zero percent interest rate. Winterfeld et al., PGP, E-PG-03, 35-36. PGP states that repayment studies should be allowed to schedule payments in advance of final due dates if the effect would be to reduce revenue requirement levels. Id. PGP suggests that BPA exclude irrigation assistance associated with projects authorized after September 7, 1966, for which payments are to be scheduled so as not to cause increases in rates. Id. It was established that these projects are not causing an increase in BPA rates. Winterfeld, PGP, TR 2000.

PGP's suggestion that the irrigation assistance payments should be included in the repayment studies as investments carrying a zero percent interest rate is consistent with maintaining the lowest level of revenue requirements, using sound business principles. There are no legal or practical reasons not to implement this suggestion.

Decision

In response to the PGP suggestion, the repayment studies are permitted to schedule irrigation assistance in advance of final due dates to provide the lowest levels of amortization allowable to repay the Federal investment in the FCRPS within a reasonable period of time. The irrigation assistance associated with projects authorized after September 7, 1966, will not be excluded because (1) they are not influencing the revenue requirement; and (2) they are obligations of the FCRPS that must be repaid.

Issue 2

Should BPA use its repayment study to schedule Supply System debt in advance of the Supply System's current plan for repayment of principal?

Evaluation of Positions

PGP states that the FCRPS revenue requirement could be reduced by exercising early redemptions for the bonds issued to finance WNP-1. Winterfeld et al., PGP, E-PG-03, 37; Initial Brief, PGP, B-PG-01, 21-22. These savings could be achieved by including the Supply System bonds within BPA's repayment study and optimizing their repayment along with the Federal investment in the FCRPS. PGP asserts that, when an LP-based repayment study model was executed, the annual principal payments and call restrictions were consistent with WNP-1 bond covenants. Id., 38-39. PGP alleges that if the opportunities for early redemption of bonds for WNP-2 and WNP-3 were added to the repayment study, further reductions in the FCRPS revenue requirement would be possible. Id.

It would be premature to model the early repayment of the Supply System bonds for purposes of lowering scheduled amortization in FY 1988 and 1989 because of the uncertainty regarding the disposition of those bonds. Roberts, BPA, E-BPA-47, 22-23. The WNP Refinancing Study, being conducted outside of the rate proceedings, is analyzing the potential for refinancing the Supply System bonds. Id. Second, an institutional factor, reduction of BPA's repayment levels to the U.S. Treasury, must be fully evaluated before this suggestion is implemented. Id. Scheduling the early repayment of Supply System debt could result in a reduction of scheduled payments to the U.S. Treasury as payments for the Supply System debt displace payments to the U.S. Treasury.

Third, PGP does not fully incorporate the complexity and diversity of the redemption provisions contained in the bond resolutions for the Supply System bonds. Id. PGP did not completely model all the complexities of Supply System bond resolutions. Winterfeld, PGP, TR 2002-2003. In its description of how WNP-1 bonds would be selected for early redemption, PGP clearly states that the model does not call the bonds in inverse order of maturities as required by the WNP-1 bond resolution. Id. Instead, the model selects bonds for early redemption based upon the highest-interest-first concept employed by BPA for Federal bonds and appropriations. Id. PGP does allege that the effect of the "penalty factor" is to derive an inverse order of maturities automatically. Id. Yet when asked specifically if a low-interest-bearing term bond would be repaid first within a particular series, consistent with the inverse order of maturities restriction, the PGP replied, "No, not at all." Id. The complexities of the Supply System bond resolutions are such that a reliance upon the highest-interest-first concept will not produce results which are consistent with these bond resolutions.

Decision

The PGP request that BPA consider the early retirement of Supply System debt is worthwhile because its implementation may result in potential savings for the FCRPS revenue requirement. It is not reasonable at this time, however, to schedule the early retirement of Supply System debt as an element of BPA's repayment study for the purpose of lowering the FY 1988 and 1989 revenue requirement. No evidence on the record responds to the three basic points: the uncertainty concerning the final disposition of the Supply System

bonds prior to the dates at which they become callable; the unevaluated institutional factors regarding BPA's repayments to the U.S. Treasury; and the inadequate demonstration of an acceptable means to model accurately the complexities of the Supply System bond resolutions. BPA is taking the prudent course to assure cost recovery within the context of what BPA now estimates its costs to be.

Issue 3

Should BPA attempt to reduce projected interest expense by assuming in the repayment studies that high-interest-bearing bonds issued to the U.S. Treasury will be refinanced?

Evaluation of Positions

PPC claims that all bonds with interest rates exceeding current U.S. Treasury borrowing rates should be refinanced with lower-interest-rate bonds when the call penalty is less than the interest savings and that BPA should borrow from the U.S. Treasury to repay the call premium. Carr et al., PPC, E-PP-03, 38-39 and Attachment N; Exceptions, PPC, R-PP-01, 18-19. PPC contends that interest expense, and therefore the revenue requirement, can be lowered by incorporating this assumption in the repayment studies. Id. PPC asserts that the refinancing should be made without considering the long-run implications for repayment and revenue requirements, because at issue is the revenue requirements for FY 1988 and 1989, not revenue requirements for future years. Carr et al., PPC, E-PP-10A2, 12-13.

The criteria used by PPC for bonds assumed to be refinanced are not clear, and no reasons were given for refinancing particular bonds at the amounts chosen. Roberts, BPA, E-BPA-47, 18. In support of its contention, PPC offers only an illustrative exhibit. Carr et al., PPC, E-PP-03, Attachment N. This exhibit, however, does not support the PPC claim that a reduction in the FCRPS revenue requirement would result from its proposal. Roberts, BPA, E-BPA-47, 18-20. Additionally, many discrepancies and inconsistencies are found in the table itself, which lead to further problems in interpreting its conclusions. Id. PPC acknowledged some errors and made some corrections. Carr, PPC, TR 2544-2545. The table and its demonstration, however, remain inconclusive.

PPC expresses concern for inequitable burdens placed upon current ratepayers as a result of not assuming prospective refinancing in the repayment studies. Carr et al., PPC, E-PP-10A2, 13. The repayment methodology used by BPA determines whether a given set of annual revenues is sufficient to repay with interest the long-term obligations of the FCRPS over the entire repayment period. BPA, E-BPA-01, 35-43. By definition it embodies a concern for the long run. BPA repayment studies must in fact demonstrate equitability through time. Without such a long-term repayment demonstration, BPA could not show whether revenues expected from current or proposed rates were sufficient. There is no evidence on the record that the cost savings anticipated by PPC will actually reduce the revenue requirements for FY 1988 and 1989. This is because any cost savings, if they occur, are equitably distributed over the entire repayment period by calculating a levelized stream

of interest and amortization payments. Id. PPC asserts that if refinancing is not assumed to occur this requires the Administrator to totally disregard the highest interest first principle. Exceptions, PPC, R-PP-01, 19. This claim is not correct. The highest interest first concept pertains to the application of revenues [DOE Order RA 6120.2, paragraph 8. c. (3)], not to the possibilities of refinancing through additional borrowing.

BPA is committed to practicing sound cash management for the purpose of minimizing the costs of the FCRPS. The PPC's argument that BPA lower the FCRPS revenue requirement by including a prospective refinancing assumption in BPA's repayment studies is not sound because it ignores the uncertainties surrounding interest rates and the availability of funds to pay any call premiums.

If, as call provisions become operative actual interest rates make refinancing of certain BPA bonds issued to the U.S. Treasury cost effective, and funds are available to pay the associated call premiums on the bonds, then BPA will undertake such refinancing. When such refinancings are undertaken, BPA plans to capitalize any associated bond premiums and amortize these capitalized bond premium assets over the remaining term of the subject bond that was refinanced. The annual costs associated with these capitalized bond premiums will be specifically identified and included in future rate proposals.

Decision

BPA will not include the refinancing of high-interest-bearing BPA bonds issued to the U.S. Treasury in the repayment studies at this time. Should BPA actually undertake U.S. Treasury bond refinancing in the future based on sound cash management practices and capitalize the associated bond premiums, the annual costs associated with these capitalized bond premiums will be separately identified in cost analyses used for determining the revenue requirements, and fully recovered through subsequent rate proposals.

Issue 4

Should BPA analyze historical replacements to assure that the projected replacements relied upon in the repayment study are accurate?

Evaluation of Positions

BPA relies upon the Corps of Engineers and Bureau of Reclamation for estimates of projected generation replacements for each project by service life. BPA, E-BPA-01A, 431.

PPC recommended that BPA adopt the use of trended generation replacements based upon historical experience instead of the replacement forecasts received from the Corps and Bureau. Carr et al., PPC, E-PP-03, 43-44; Exceptions, PPC, R-PP-01, 20. PPC advocated a linear regression based upon historical replacements to predict future replacements. Id. PPC states that "the blind-faith reliance by BPA on Corps and Bureau replacements projections

without reference to historical reality is a questionable practice." Carr et al., PPC, E-PP-10A2, 17. Later in the proceeding PPC states that BPA should analyze historical generation and transmission replacements to assure that the estimates relied upon in the repayment study are accurate. Initial Brief, PPC, B-PP-01, 24; Exceptions, PPC, R-PP-01, 20.

Sufficient justification to substitute the detailed generation replacements data provided by the Corps and Bureau with the results of a linear regression has not been provided for the record. Roberts, BPA, E-BPA-47, 8. Additionally, no evidence on the record demonstrates how specific repayment periods for specific types of plant by project could be provided by using a linear regression. Id.

Finally, the historical data that the PPC relied upon do not provide a valid basis for estimating projected generation replacements. Roberts, BPA, E-BPA-47, 8. It has been established that the estimates of historical data for generation replacements are reasonable, given the assumption BPA made in developing the data. Carr, PPC, TR 2625. The data are not of sufficient quality, however, to be used to construct a linear regression: the estimates of historical replacements are uniform over time and do not increase as the project ages. Id. Also, the starting date of the historical data as defined by the PPC is arbitrary -- it does not consider projects placed into service prior to that date and it is several years before the major initial investment at Bonneville Dam was completed. Carr, PPC, TR 2629-2632. No historical data of sufficient quality exist by which to forecast future replacements. BPA's treatment of replacements is consistent with prior rate cases and practices of other PMAs. Without acknowledgement of and adjustments for these shortcomings in the estimates for historical replacements, these data cannot be used to forecast future replacements.

Decision

No evidence on the record calls into question the validity of the estimates of projected replacements provided by the Corps and Bureau. It is unfortunate, but nevertheless the case, that there are no historical data of sufficient quality with which to analyze the veracity of the forecasts projected by the Corps and Bureau. Both the Corps and Bureau are the most knowledgeable sources of these data, and it is reasonable to rely upon their projections.

D. Revenue Requirement Study

Issue 1

Should depreciation expense be omitted from FCRPS revenue requirement considerations?

Evaluation of Positions

BPA determined that depreciation expense is an annual operating expense of BPA, Corps, and Bureau facilities and the write-down (amortization) of

Conservation and Fish and Wildlife investments. BPA, E-BPA-01, 34. The straight-line method of depreciation is used for all plant-in-service, incorporating relevant average service lives. Id. The methodology for this rate proposal is consistent with that of the 1985 final rate proposal. 1985 Rates ROD, WP-85-A-02, 120. Depreciation was included in the total revenue requirements presented in BPA's Cost of Service Analyses prepared in the 1979, 1981, 1982, 1983, and 1985 rate proposals. Roberts, BPA, E-BPA-47, 4. BPA testimony presented for the 1985 rate proposal stated that, in the development of revenue requirements, "the first step is to determine BPA's annual expenses (including depreciation). . . . A provision for depreciation is included in the annual expenses to fully account for all annual costs of providing BPA's service." Meyer, BPA, WP-85-E-BPA-19, 1.

PGP claims that "BPA has mixed elements of the accrual basis and cash basis for determining its revenue requirement" by including depreciation. Winterfeld et al., PGP, E-PG-03, 26-31. PGP further claims that the "mixing of these rate concepts overestimates the total of depreciation and interest expense, as compared with the results of following either the accrual- or cash-basis methodologies." Id. PGP states that the same set of expenses can be accounted for in a variety of ways, but BPA's intermingling of methods overstates the revenue requirement. Exceptions, PGP, R-PG-01, 8. PPC states that depreciation should be removed from the Revenue Requirement Study. Carr et al., PPC, E-PP-03, 45.

PGP's claim that BPA has mixed elements of the accrual basis and cash basis for determining revenue requirements stems from the fact that BPA considered depreciation in the determination of the revenue requirement. Roberts, BPA, E-BPA-47, 5. The first step in determining the revenue requirement is performed in Table 1, Functionalized Total Expenses, Roberts, BPA, E-BPA-35, Attachments 1 and 2, which includes all projected expenses including depreciation and interest expense. Roberts, BPA, E-BPA-47, 5. It is essential for BPA to project all expenses, including depreciation and interest, when determining revenue requirements for recovery of all costs. Id. The requirement that BPA must recover all expenses is supported in initial and rebuttal testimony. Roberts, BPA, E-BPA-15, 18; E-BPA-47, 5. The calculation of total expenses on Table 1 provides the required benchmark for this important test of cost recovery. Id.

BPA concurs with PGP's statement that expenses can be accounted for in a variety of ways. BPA determines the FCRPS revenue requirement in a manner that recovers its total annual costs but does not produce a result that exceeds a revenue requirement determined on a cash basis as defined by PGP. Roberts, BPA, E-BPA-47, 6. The FCRPS revenue requirement as determined by BPA fully recovers all annual costs and satisfies BPA's cash needs (amortization) on a projected basis. Roberts, BPA, E-BPA-47, 5-6. Including depreciation in financial reporting and revenue requirements is also consistent with the requirements of DOE Order RA 6120.2, paragraphs 6.a., 8, 9, and 12, and BPA's goal of maintaining cost recovery of the FCRPS.

Decision

It is appropriate for BPA to consider depreciation in revenue requirements. This practice continues from the practice employed in the 1985 and prior rate proposals. Recently the Federal Energy Regulatory Commission found that Bonneville's methodology follows common utility practices. United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates for the 1985 Rate Filing On A Final Basis And Terminating Dockets, Dockets Nos. EF85-2011-001 et al., FERC ¶II,B.2, (April 29, 1987).

Issue 2

Do FCRPS revenue requirements incorporate a "double-counting" effect if depreciation expense is considered in the revenue requirements and replacements are included in the repayment studies?

Evaluation of Positions

Depreciation was considered in the total revenue requirements presented in BPA's Cost of Service Analyses prepared in the 1979, 1981, 1982, 1983, and 1985 rate proposals. BPA testimony presented for the 1985 rate proposal stated that depreciation is included as an annual expense in order to fully account for all annual costs. Meyer, BPA, WP-85-E-BPA-19, 1. (Further analysis of depreciation has been provided in Issue 1, supra.)

Replacements for the FCRPS have been provided in repayment studies for the 1987 rate proposal using the same methodology as used in the 1985 and prior proposals. 1985 Rates ROD, WP-85-A-02, 53. Replacements are projected for transmission and generation facilities based on the age of the equipment. Id., 55. The methodology of including replacements in repayment studies complies with DOE Order RA 6120.2, ¶10,(e). The supporting detail for replacements can be found in the Documentation and Appendices for the Revenue Requirement Study, E-BPA-01A, Chapter 14, 431.

PPC's Initial Brief takes the position of PPC testimony that "[t]he use of both depreciation and replacements in the Revenue Requirement Study amounts to double-counting. This result occurs because, in the absence of ISC (Investment Service Coverage), both of these items increase the revenue requirement to compensate BPA for the same loss of value of its assets through time." Carr et al., PPC, E-PP-03, 45; Initial Brief, PPC, B-PP-01, 24. PPC goes on to state that "[c]onsistent with DOE Order RA 6120.2, replacements should be included in the repayment study for the stated purpose of maintaining the capacity of the system. Depreciation should be removed from the Revenue Requirement Study, since it is unnecessary, confusing, and may lead to double counting." Carr et al., PPC, E-PP-03, 46; Exceptions, PPC, R-PP-01, 22. However, PPC has not provided a demonstration or evidence to support its assertion that the "double-counting" effect exists.

In Issue 1 above, depreciation has been identified as an annual expense appropriately considered in meeting full cost recovery of the FCRPS when

determining revenue requirements. Repayment studies appropriately include replacements, consistent with DOE Order RA 6120.2 as the PPC states; replacements are included in repayment studies to calculate amortization (and indirectly interest) to be incorporated in revenue requirements. Depreciation and replacements are entirely separate, distinct, and nonadditive concepts which lead neither to "double-counting" nor increases in the revenue requirement. Roberts, BPA, E-BPA-47, 6.

PPC agrees in its Brief on Exceptions that replacements and depreciation are nonadditive but alleges that revenue requirement effects of the two concepts are additive. Exceptions, PPC, R-PP-01, 22. Given the PPC's acknowledgment that replacements and depreciaton are nonadditive, its position regarding the additive revenue requirement effects appears both confusing and inconclusive. The PPC does not demonstrate this additive effect, or explain its significance in light of the differences between depreciation and replacements. The parties have not demonstrated a "double-counting" effect in revenue requirements.

Decision

It is appropriate to consider both depreciation and replacements in developing FCRPS revenue requirements; this does not result in a "double-counting" of costs.

Issue 3

Should the nondebt-related costs of the Hanford Generating Project (HGP) be eliminated from proposed studies?

Evaluation of Positions

HGP costs are shared by two investor-owned utilities and numerous public agency participants, in accordance with governing contracts. BPA, E-BPA-01, 23. BPA is obligated to pay the public agency share of HGP operating costs (72 percent) and 100 percent of the debt service through net-billing agreements. Id. The remaining share of the HGP operating budget is paid by the IOUs through trust fund arrangements and is not included in BPA revenue requirements. Id.

PPC suggests that HGP nondebt-related costs are inappropriately included in the FCRPS revenue requirements, due to (1) the uncertainty that the N Reactor will continue to operate and (2) the lack of cost effectiveness of the power produced by HGP. Carr et al., PPC, E-PP-03, 46; Initial Brief, PPC, E-PP-01, 24. PPC also contends that Hanford power is surplus to the region. Id.

The level of nondebt-related costs is provided by BPA's budgetary process and has never been subject to change in the rate proceedings. 1985 Rates ROD, WP-85-A-02, 47. Debt service costs are also obtained from BPA's budget process. BPA, E-BPA-01A, 381. PPC supports BPA's planned reduction of HGP costs where possible. Exceptions, PPC, R-PP-01, 21.

Decision

The current contracts and agreements with the HGP prohibit total deletion of nondebt-related costs at this time. However, the U.S. Department of Energy has tentatively agreed to reduce steam rates to a level that virtually ensures that variable costs will not exceed the revenue BPA receives from the sale of HGP energy. The nondebt-related costs of Hanford in the revenue requirement have been reduced accordingly.

Issue 4

Has BPA given adequate consideration to the impacts of its cash management practices on future revenue requirements?

Evaluation of Positions

In accordance with a FERC order, BPA determines separate revenue requirements for the generation and transmission components of the FCRPS. BPA, E-BPA-01, 1. Included in the determination of the revenue requirements are the results of separate repayment studies for the projected interest and amortization payments associated with generation and transmission investments. Id. In practice, BPA's cash balances are managed according to the benefits provided to the entire FCRPS, not for the singular benefit of either component function. Roberts, BPA, E-BPA-15, 34. To dispose of funds otherwise would be detrimental to the system as a whole. Id.

PGP is concerned that BPA has failed to give adequate consideration to the potentially detrimental long-term impacts of its cash management practices. Winterfeld et al., PGP, E-PG-03, 40. PGP contends that BPA "fails to ensure the long-term benefits of its cash management practices through analysis of the impact on revenue requirements." Initial Brief, PGP, B-PG-01, 22. PGP further states that BPA has not considered the impact of shifting scheduled amortization from generation investments to transmission investments, which will improperly increase generation costs and decrease transmission costs in the long run. Id., 23.

Although the cash disposition incorporated in the separate revenue requirements (scheduled amortization) demonstrates that revenues will be adequate to repay Federal investment, the actual disposition of funds is affected primarily by BPA's financial conditions at that time. Roberts, BPA, E-BPA-15, 35. For example, at the end of FY 1986 BPA needed to take actions to cope with projected revenue underruns in FY 1987 so that amortization payments and interest expense would be met in that year. Id., 34. BPA paid the full amount of amortization scheduled for FY 1986 by the 1985 final rate proposal, although the payment was not applied to the specific investments as planned. Id., 32. In initial testimony BPA presented a table demonstrating that, with the same total payment, the weighted average interest rate associated with the actual payment was markedly higher than that associated with the plan. Id., 33. This prudently reduced system-wide interest expense in FY 1987 (and beyond), minimizing BPA's costs consistent with sound business principles. Id.

PGP finds BPA's goal of lowering interest and adhering to scheduled amortization laudable. Winterfeld et al., PGP, E-PG-03, 40. However, PGP states that, prior to making the payment, BPA did not confirm that the shifting of amortization payments from generation to transmission investments would reduce the combined revenue requirements for FY 1988 and 1989. Id., 42. PGP believes that interest rates should not be the sole consideration, but that the repayment studies must be used in order to determine the full effect when amortization schedules are revised. Id., 43.

PGP further contends that "BPA considers funds for amortization to be available for either generation investment or transmission investment, regardless of source of these funds or the relative schedule of investment repayment for each function." Initial Brief, PGP, E-PG-01, 22. PGP is concerned that the transfer of amortization payments from generation to transmission investments may present a significant impact on the generation system over time. Winterfeld et al., PGP, E-PG-03, 46. PGP recommends that, if BPA is opposed to interfunctional loans, a rate-process adjustment or use of the equivalent annual costs should be considered to correct the problem. Id., 45.

PGP is incorrect in asserting that BPA makes no consideration of the source of funds: as a part of its rate proposal BPA is committed to providing FERC with a separate accounting of actual transmission (both Federal and non-Federal) and generation costs and revenues to support the identification and equitable allocation of transmission costs in its rate case. See BPA's Request for Approval of 1985 Proposed Wholesale Power and Transmission Rate Adjustments, April 26, 1985, Attachment 2. The separate accounting statement demonstrates that transmission revenues are used to repay transmission costs and that costs assigned to transmission are transmission-related costs. 25 FERC ¶61,140. In approving BPA's 1985 rate proposal, FERC determined that the separate accounting statement included in the rate filing demonstrated this. United States Department of Energy - Bonneville Power Administration, Order Confirming and Approving Rates for the 1985 Rate Filing On A Final Basis And Terminating Dockets, Docket Nos. EF85-2011-001 et al., FERC ¶II,B.2, (April 29, 1987). The separate accounting analysis is essential for relating cash management practices to revenue requirement determinations. PGP ignores this element when it claims that generation costs are improperly increased and revenue requirements are higher than necessary in the long run. Exceptions, PGP, R-PGP-01, 8.

Decision

The most influential elements affecting BPA's cash management are the actual conditions at the time decisions must be made. In FY 1986 BPA's specific cash management consideration was to ensure the ability to make interest and amortization payments in FY 1987 in the face of revenue underruns. In this particular instance BPA did not explicitly ensure long-term benefits to the separate functions, although the application of sound business principles and prudent cash management practices substantially reduced system-wide interest expense in FY 1987 as well as in subsequent years. Since it is theoretically possible to raise system-wide revenue requirements subsequent to the immediate interest savings, BPA will explicitly

consider both the interest savings and the effect on future revenue requirements in similar future circumstances. In addition, BPA will continue to rely on the separate accounting required by FERC as the measurement of functionalized funds from operations available for amortization payments. BPA is not opposed to some type of adjustment between generation and transmission if warranted. Due to the timing of the availability of the separate accounting information, any adjustment would, of necessity, be after the fact.

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CHAPTER V

MARGINAL COST ANALYSIS

A. Introduction

The Marginal Cost Analysis (MCA) measures the additional costs BPA would incur to generate and transmit electricity on a seasonal, daily, and hourly basis as a result of serving additional long-term capacity and energy load.

The results of the marginal cost analysis are used throughout the development of BPA's wholesale power and transmission rates. The relative marginal costs of generation capacity and energy are used to classify generation costs to capacity and energy. The diurnal and seasonal differentiation of the capacity charge also are developed according to the results of the MCA. The Reserve Power rate is based directly on illustrative marginal cost rates calculated in the MCA. The Unauthorized Increase Charge, which is part of most firm power rate schedules, also is calculated using data generated in the MCA.

B. Classification of Capacity and Energy Costs

BPA uses a peak-credit approach to classify generation costs to capacity and energy. The peak-credit calculation is the process by which a portion of the costs associated with serving an increment of additional load are assigned to the capacity (or peaking) component of that load, while the remainder of the additional costs are associated with the energy component of that load.

Parties raised many issues pertaining to the classification of costs to capacity and energy. A water heater load management program was proposed as BPA's least-cost capacity resource. If the costs of a load management program are used in the peak-credit calculation and they are less than the costs of a combustion turbine, then more costs would be allocated to energy and less to capacity. The plant factor of the capacity resource is also important to the peak-credit calculation. The higher the operation level of the capacity resource, the greater the capacity classification percentage. The reserve factor used in the peak-credit calculation also affects the classification of costs. A higher reserve factor would cause more costs to be allocated to energy. The rate of technical innovation of generation is also at issue in this rate case. The rate of technical innovation affects the present value or levelized capital costs of a resource. A positive rate of technical innovation applied to the capacity resource costs used in the peak-credit calculation would increase the share of costs allocated to capacity.

Issue 1

What is BPA's least-cost capacity resource to be used as a proxy for capacity costs in the peak-credit calculation?

Evaluation of Positions

The MCA uses the costs of a CT as the least-cost capacity resource to credit against the total marginal cost of generation to separate out the marginal costs of capacity and energy. BPA, E-BPA-03, 10-12; Wedlund/Emery, BPA, E-BPA-19, 6.

WPAG claims that BPA should use the costs of a residential water heater load management program in the peak-credit calculation. WPAG states that a residential water heater program is the region's least-cost capacity resource. Saleba et al., WPAG, E-WA-02, 45-46; Initial Brief, WPAG, B-WA-01, 30. The peak-credit method using the load management costs presented by WPAG results in a classification of 17 percent to capacity and 83 percent to energy. Saleba et al., WPAG, E-WA-02, 45-47, Attachment 8.

NIU states that a residential water heater load management program is not BPA's least-cost capacity resource. Kavanaugh, NIU, E-NI-06, 2-3. The load management program could not effectively meet BPA's peak loads because the duration of the peak is too long for the load management program to effectively shift load to the offpeak period. Kavanaugh, NIU, E-NI-06, 2-5. NIU also states that WPAG ignores the operating characteristics of a load management program that would tend to increase the costs of the program. Kavanaugh, NIU, E-NI-06, 5-8. Adjusting the costs provided by WPAG as suggested by NIU makes the load management program more expensive than a CT and, therefore, inappropriate for the peak-credit calculation. Id.

APAC/DSI states that WPAG understates the costs of a load management program in a number of ways. APAC/DSI claims that WPAG incorrectly assumes that the reliability of the load management system is equal to the reliability of the load management device, that WPAG does not include the costs of an incentive payment needed to attract customers to the program, and that WPAG has overestimated the capacity savings from the load management system. Wolverton/Schoenbeck, E-PA/DS-01, 15-22; E-PA/DS-02R, 6-8; E-PA/DS-03SR, 6-9. APAC/DSI concludes that the costs of a load management program are inappropriate for the peak-credit calculation. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 15-22; E-PA/DS-02R, 6-8; E-PA/DS-03SR, 6-9; Initial Brief, APAC/DSI, B-PA/DS-01, 15-18; Initial Brief, APAC, B-PA-01, 3.

WPAG underestimates the costs of a load management program. The costs presented by WPAG incorrectly omit expenses associated with a marketing program and an annual incentive payment to participating customers. Wedlund/Emery, BPA, E-BPA-51, 2-3; E-BPA-60, 1-3; Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 20; E-PA/DS-02R, 7; E-PA/DS-03SR, 7; Initial Brief, APAC/DSI, B-PA/DS-01, 17. The experiences of utilities with load management systems indicate that both an intensive marketing program and an incentive payment are necessary to attract large numbers of customers to the program. Wedlund/Emery, BPA, E-BPA-51, 2-3.

Decision

There is compelling evidence that a load management program is a more costly capacity resource than a CT. Therefore, the costs of a CT rather than

the costs of a load management program are used to value capacity in the peak-credit calculation.

Issue 2

How should the combustion turbine (CT) plant factor be estimated for the peak-credit calculation?

Evaluation of Positions

A CT plant factor of 1 percent was used in the initial MCA as part of the peak-credit calculation to estimate the marginal cost of generation capacity and energy. BPA, E-BPA-04, 13. The CT plant factor is calculated using the monthly version of the System Analysis Model (SAM) to estimate CT operation with the existing system over the 19-year planning horizon. BPA, E-BPA-04, 13; Wedlund/Emery, BPA, E-BPA-51, 7-8.

NIU argues in favor of using 3 percent as the CT plant factor because 3 percent is approximately equal to the average of CT plant factors from four different sources. Kavanaugh, NIU, E-NI-04, 8-9; E-NI-09, 4. The 3 percent CT plant factor proposed by NIU is also approximately equal to the CT plant factor BPA utilized in the 1983 rate case. Kavanaugh, NIU, E-NI-04, 8-9. However, the average CT plant factor proposed by NIU incorporates data from systems that are substantially different from BPA's or the region's, and thus do not represent a good estimate of CT operation in the Pacific Northwest. Wedlund/Emery, BPA, E-BPA-51, 9; Saleba et al., WPAG, E-WA-03, 17-18. The estimate of CT operation calculated from the results of SAM is specific to the Pacific Northwest and reflects the level of CT operation needed to meet regional loads. Wedlund/Emery, BPA, E-BPA-51, 9.

In surrebuttal testimony, NIU proposed a CT plant factor of 1.5 percent based on the average of CT operation from SAM in years when CT operation is greater than zero. Kavanaugh, NIU, E-NI-09, 5. Although NIU states that its proposal "would be more in keeping with the notion of long-run incremental costs," than the BPA proposal, NIU does not substantiate its statement. Kavanaugh, NIU, E-NI-09, 5. NIU does not give any reason for excluding years without CT operation from the average of CT operation.

APAC/DSI maintains that BPA should use a 2.8 percent CT plant factor. APAC/DSI claims that BPA's method of estimating the CT plant factor neglected to consider the characteristics of its peak load because the monthly SAM was used rather than the hourly SAM, making it inconsistent with BPA's peak credit cost theory. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 5-6; Initial Brief, APAC/DSI, B-PA/DS-01, 3. Exceptions, DSI, R-DS-01, 8. Since the hourly SAM is unavailable to estimate CT operation for capacity needs, APAC/DSI proposes that BPA estimate the CT plant factor by analyzing the amount of CT operation needed to serve the incremental peak load. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 5-8; Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-03SR, 2-4; Initial Brief, APAC/DSI, B-PA/DS-01, 3-4. PGP supports the APAC/DSI position on the CT plant factor. Garman et al., PGP, E-PG-02, 11-12. When the hourly SAM was used in the 1985 rate case to determine CT operation for capacity needs, the

results showed very little additional operation over the results of the monthly SAM. Wedlund/Emery, BPA, E-BPA-51, 7. The monthly SAM provides a reasonable assessment of CT operation in the region, since the additional operation that would be indicated by the hourly SAM would not change the results significantly. Id. The APAC/DSI proposal ignores the contribution of the existing system's capability to meet peak load. Wedlund/Emery, BPA, E-BPA-51, 6-8; Granat, PP&L, E-PL-01R, 2-6; Initial Brief, PP&L/PGE, B-PL/GE-01, 40-41; Saleba et al., WPAG, E-WA-03, 13-17; Initial Brief, WPAG, B-WA-01, 31.

Decision

The CT plant factor should be estimated using the monthly SAM. The results of this model are not significantly different than the results of the hourly SAM.

Issue 3

What are the appropriate data sources for CT costs and financial assumptions for the peak-credit calculation?

Evaluation of Positions

The MCA for BPA's initial proposal used the 1982 EPRI TAG as the source for CT cost data. BPA, E-BPA-04, 12; Wedlund/Emery, BPA, E-BPA-51, 5-6. The 1985 Generating Resource Supply Curves is the source for the CT heat rate in the initial proposal, and financial data such as inflation, escalation, and interest rates were taken from DRI forecasts. BPA, E-BPA-04, 12-13; Wedlund/Emery, BPA, E-BPA-51, 5-6.

NIU maintains that BPA ignored current data in the formulation of many of its assumptions affecting the peak-credit calculation. Kavanaugh, NIU, E-NI-04, 5-7; Initial Brief, NIU, B-NI-01, 12-13. NIU alleges that using data from disparate sources "gives rise to questions about the logical consistency of [BPA's] calculated capacity/energy split." Kavanaugh, NIU, E-NI-04, 6. NIU also points out that BPA uses inflation, interest, and discount rates that are inconsistent. Kavanaugh, NIU, E-NI-04, 12; Initial Brief, NIU, B-NI-01, 13. NIU recommends using either the 1986 EPRI TAG or the Generating Resource Supply Curves as the source of CT cost data, but not both. Kavanaugh, NIU, E-NI-04, 14. APAC/DSI also recommends that BPA use CT cost data from the 1986 EPRI TAG. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 8.

PP&L recommends that the 1986 Northwest Conservation and Electric Power Plan (Council's Plan) be used as the source for all CT cost data. Granat, PP&L, E-PL-01R, 10. PP&L alleges that the Council's Plan is the best source for CT cost data since it provides a recent assessment of cost conditions specific to the Northwest. Id. However, the 1986 EPRI TAG offers a more recent assessment of CT cost than the Council's Plan and provides adjustments to match the specific conditions of the Pacific Northwest. Wedlund/Emery, BPA, E-BPA-51, 6; Kavanaugh, NIU, E-NI-09, 2-3.

In preparing the initial proposal BPA used the most current CT cost data available. Wedlund/Emery, BPA, E-BPA-51, 5-6. More current cost data have since been published. It is appropriate to update capital costs, the O&M costs, and the heat rate from the 1986 EPRI TAG for the final MCA. Id. The financial assumptions will be revised for the final MCA to make them consistent with BPA's 1987 Resource Strategy and to correct the inconsistency pointed out by NIU. Wedlund/Emery, BPA, E-BPA-51, 6.

Decision

The 1986 EPRI TAG is more recent than the 1982 EPRI/TAG and represents the most appropriate data source for CT capital costs, O&M costs, and heat rate. The 1987 Resource Strategy is the most appropriate source for the financial assumptions, since those assumptions are incorporated in the LCMM and SAM.

Issue 4

What is the appropriate load factor for calculating the levelized marginal cost of power?

Evaluation of Positions and Decision

The initial MCA uses the average system plant factor over the planning horizon to express the marginal cost of power in term of peakload. BPA, E-BPA-04A, 7.

APAC/DSI endorses using a load factor of 58 percent to be consistent with the load factor of the incremental load. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 8. APAC/DSI charges that the improper application of methodology causes too much of BPA's costs to be allocated to energy. Initial Brief, APAC, B-PA-01, 2; Initial Brief, APAC/DSI, B-PA/DS-01, 2-7. PGP and PP&L support the APAC/DSI proposal for system load factor. Garman et al., PGP, E-PG-02, 11-12; Granat, PP&L, E-PL-01R, 11. However, the MCA measures cost changes as a function of system operation changes. Therefore, it is appropriate to use the average system load factor when analyzing these costs rather than the load factor of the incremental load. Wedlund/Emery, BPA, E-BPA-51, 8.

Issue 5

What is the appropriate reserve factor for use in the peak-credit calculation?

Evaluation of Positions and Decision

In PP&L's calculation using the peak-credit method, PP&L uses a reserve factor that is specific to a CT rather than the average reserve factor of the incremental resources identified by the Least Cost Mix Model (LCMM). Granat, PP&L, E-PL-01R, 2 and 6; Initial Brief, PP&L/PGE, B-PL/GE-01, 37-39. In the peak-credit methodology it is not assumed that a CT is actually used to meet

peakload; the peak-credit calculation values the capacity provided by the incremental resources identified by the LCMM. Wedlund/Emery, BPA, E-BPA-60, 3; Kavanaugh, NIU, E-NI-09, 2. Therefore, it is appropriate to use the average reserve factor of the incremental resources in the peak-credit calculation rather than the reserve factor of a CT alone.

Issue 6

Is it appropriate to assume a zero percent rate of technical innovation in estimating resource costs?

Evaluation of Positions

In the preparation of the initial MCA, BPA assumed a technical innovation rate of zero percent, consistent with previous rate proposals. Wedlund/Emery, BPA, E-BPA-51, 9-10.

NIU states that a 1.2 percent rate of technical innovation should be taken into account in the development of the levelized CT capital costs. Kavanaugh, NIU, E-NI-04, 10-12; Kavanaugh, NIU, E-NI-09, 3-4 and 8-9. NIU asserts that by ignoring the rate of technical innovation, BPA underestimates the capital costs associated with a CT, which results in too many costs being classified to energy and not enough to capacity. Id.

Both WPAG and PP&L disagree with NIU's technical innovation proposal. PP&L states that while the studies supporting NIU's proposal and other studies conducted in the 1960s and early 1970s indicated positive rates of technical change, more recent studies show negative rates of technical change. Granat, PP&L, E-PL-01R, 8. PP&L claims that its own estimate of technical innovation indicates a rate of -0.8 percent per year. Id. NIU characterizes the PP&L estimate of technical innovation as "naive," but NIU fails to state why this is the case. Kavanaugh, NIU, E-NI-09, 4.

WPAG claims that NIU does not provide sufficient evidence to substantiate the technical innovation proposal. Saleba et al., WPAG, E-WA-03, 18-19. WPAG states that "technological change is generally considered to be too unpredictable to include in levelized cost analysis." Saleba et al., WPAG, E-WA-03, 19; Initial Brief, WPAG, B-WA-01, 31-32. WPAG also charges that NIU does not apply its technical innovation proposal in a uniform manner, since NIU proposes to apply the 1.2 percent rate of technical innovation to the costs of a CT but not to the costs of the incremental resources identified by the LCMM. Saleba et al., WPAG, E-WA-03, 19-20.

While a positive rate of technical improvement seems reasonable on the surface, the regulatory environment of the utility industry is such that one might expect a zero or negative rate of technical improvement. Wedlund/Emery, BPA, E-BPA-51, 10-11. The evidence presented by NIU, PP&L, and WPAG does not lead to a clear conclusion on the direction (positive, negative, or zero) of the rate of technical innovation in electric power generation.

Decision

A zero percent rate of technical innovation in estimating resource costs is approriate.

Issue 7

What is the appropriate incremental load for measuring the marginal cost of generation?

Evaluation of Positions

In the MCA for the initial proposal, an incremental load of 500 average megawatts and 855 peak megawatts over the expected load, as measured by the 1986 Longterm Load Forecast, is used to measure the marginal cost of generation. Wedlund/Emery, BPA, E-BPA-19, 3-4.

APAC/DSI states that the cost associated with the increment of load between present load and expected load should be used to measure the marginal cost of generation. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 4. APAC/DSI claims that measuring the marginal cost using the 500 aMW increment over expected load causes the classification of costs to capacity and energy to be biased toward allocating an inappropriately large proportion of costs to energy. Id.

WPAG states that "if anything, the load perturbation used by BPA is understated" because the load increment should be the size of the primary incremental resources, which are WNP-1 and WNP-3. Saleba et al., WPAG, E-WA-03, 14.

The assertion of APAC/DSI that the use of the 500 aMW increment over expected load biases the capacity/energy relationship is incorrect. The use of the increment over expected load may alter energy costs but it also affects the level of CT operation and consequently would affect capacity costs as well. Wedlund/Emery, BPA, E-BPA-51, 8-9. The MCA measures the costs caused by an unexpected increase in system load as represented by the addition of 500 aMW to expected load. Id.

Decision

An increment of 500 average megawatts over expected load is appropriate to measure the marginal cost of generation. Such an increment does not bias the results toward higher energy costs.

Issue 8

What are the appropriate classification percentages for allocating costs to energy and capacity?

Evaluation of Positions

Besides offering technical arguments (described in Issues 1-7 above) many parties offered more general arguments concerning the classification of costs to energy and capacity.

PSP&L/MPC/WWP states that the adjustment of the classification percentages from 74 percent energy/26 percent capacity to 80 percent/20 percent is unsupportable in the absence of a change in the resource picture and erroneously assigns undue weight to current economic factors. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 23-24; Exceptions, PSP&L et al., R-PS/MP/WP-01, 6, The assertion of PSP&L et al., is not supported by any arguments of a technical or quantitative nature. The revision of the classification percentages is appropriate since factors other than the resource picture (such as the cost of fuel, declining interest rates, and an extended period of surplus resources), have caused the relative marginal costs of capacity and energy to change. BPA, E-BPA-04, 9-14. Recognizing that current economic factors influence investment decisions and future costs is neither unsupportable or erroneous.

APAC states that high load factor customers have been burdened with more and more energy-intensive rates. Oral Argument, APAC, 3111. APAC also argues that the classification of more costs to capacity enhances BPA's marketing opportunities since the extraregional market can absorb an increase in the capacity rate, enhancing the potential for cost recovery. Id., 3112. APAC also maintains that capacity will become more valuable over time inside and outside the region, and as such, BPA will be less constrained in recovering its costs from these markets. Exceptions, APAC, R-PA-01, 6. The APAC assertion that classification of more costs to capacity improves BPA's probability of revenue recovery was made during oral arguments and was not accompanied with quantitative evidence. WPAG states that it is not necessary to skew the classification of capacity and energy costs to improve the marketability to California since the SL and SP rate schedules contain sufficient flexibility to respond to market conditions. Oral Argument, WPAG, 3032. Furthermore, there is no evidence on the record to support the APAC assertions.

Decision

There is compelling evidence that the 80 percent/20 percent energy/capacity split, as developed in the MCA, is appropriate. There are many factors other than the resource mix that can necessitate a change in classification percentages. The arguments presented by APAC for increasing the portion of costs allocated to capacity are not persuasive.

C. Seasonalization of Capacity and Conservation Costs

Parties raised a number of issues relating to the seasonal differentiation of costs. Besides proposing different methods of uniformly differentiating

costs, it is also proposed that conservation costs be seasonally differentiated differently than other energy-related costs.

Issue 1

Should BPA seasonally differentiate capacity costs?

Evaluation of Positions

In the initial MCA, the seasonalization of capacity costs is determined using the Coordination Agreement Reserve Planning (CARP) Model to estimate loss of load probabilities (LOLPs) for the period OY (Operating Year) 1988 through OY 1993. BPA, E-BPA-04, 29-30; E-BPA-04A, 57-62; Wedlund/Emery, BPA, E-BPA-19, 8-9. The current method used differs from the method used in the 1985 rate case in that the relative costs between seasons are determined using the LOLPs which are calculated without the Firm Peak Load Carrying Capability (FPLCC) adjustment. Wedlund/Emery, BPA, E-BPA-19, 9-10. The capacity surplus during all months of the year causes the LOLPs in every month to be zero and, therefore, implies no relative difference in the marginal cost between seasons. BPA, E-BPA-04, 29-30; Wedlund/Emery, BPA, E-BPA-19, 8-10. BPA conducted capacity studies in its 1986 Pacific Northwest Loads and Resources Study, indicating that the least amount of marketable surplus capacity was available during the late summer and early fall. Id., 19. The results of those studies support a peak capacity season in the fall rather than the winter. The results of those capacity studies call into question the appropriateness of a peak winter season and make uniform capacity rates seem more reasonable. Id., 20.

NIU recommends allocating 80 percent of capacity costs to the winter season and 20 percent to summer. Kavanaugh, NIU, E-NI-04, 17-18. NIU justifies this seasonalization by citing the relative occurrences of curtailment between the seasons as reported by SAM. Kavanaugh, NIU, E-NI-04, 16-18; E-NI-09, 9-10. NIU criticizes the LOLP analysis for the 7-year duration of the study as opposed to the 20 years used in the rest of the MCA; the LOLPs' sensitivity to planned maintenance schedules of generating plants; and the fact that the "conditions facing the FBS do not seem to have changed materially [since the 1985 proceeding] to justify a radically different expectation about the likelihood of not serving loads." Kavanaugh, NIU, E-NI-04, 16.

APAC/DSI states that there "is no convincing reason for BPA to abandon its traditional seasonal differentiation of demand charges." Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 13; Initial Brief, APAC/DSI, B-PA/DS-01, 9. However, this is somewhat different than APACs position that the extra-regional market can absorb an increase in the capacity rates. Exceptions, APAC, R-PA-01, 5-6. The extra-regional market for capacity exists primarily in the summer.

Big Bend Electric Cooperative (BBEC) and Columbia Rural Electric Association (CREA) state that BPA should retain a seasonally differentiated demand charge. While stating that BPA "erred" by using LOLPs without the FPLCC adjustment, BBEC and CREA fail to explain why and how there was an

error. Big Bend Electric Cooperative and Columbia Rural Electric Association, Richland Field Hearing, February 11, 1987, page 67. In the place of the LOLP analysis BBEC and CREA recommend an analysis of monthly loads. Id., page 68.

Extending the duration of the LOLP analysis from 7 to 20 years, as suggested by NIU, would not significantly alter the results of the analysis since BPA's capacity surplus is forecasted to last to the end of the 20-year planning horizon. Wedlund/Emery, BPA, E-BPA-51, 11. In NIU's own analysis of different planned maintenance schedules, the resulting LOLPs without the FPLCC adjustment remain zero. Kavanaugh, NIU, E-NI-09, Exhibit 1 and Exhibit 2. Therefore, although it is true that the CARP results, after making the FPLCC adjustment, are sensitive to planned maintenance schedules, the CARP results without the adjustment are stable under various adjustments to the maintenance schedules. The method recommended by NIU to seasonally differentiate the demand charge using the curtailments reported by SAM is inappropriate because the curtailments represent potential energy shortages rather than capacity shortages. Wedlund/Emery, BPA, E-BPA-51, 11. Although NIU offers BPA two different CARP runs with "corrected" maintenance schedules, NIU fails to justify its use of the LOLPs with the FPLCC adjustment rather than the LOLPs without the FPLCC adjustment. Kavanaugh, NIU, E-NI-09, 9-10.

Decision

BPA's projected capacity surplus throughout the planning horizon eliminates the need for seasonal differentiation if marginal capacity costs. The LOLPs without the FPLCC adjustment clearly and correctly identify this condition. The LOLPs with the FPLCC adjustment are inappropriate for estimating the seasonal differentiation of capacity costs. The FPLCC adjustment biases the LOLP results and makes them dependent upon changes in maintenance schedules.

Issue 2

Should BPA seasonally differentiate conservation costs in the same manner as other energy-related costs?

Evaluation of Positions

NIU states that "using a uniform seasonal split understates the true seasonal variation in these [conservation] costs and distorts the perception of who benefits." Kavanaugh, NIU, E-NI-04, 27. NIU charges that since "the benefits of the dollar expenditures for the bulk of the conservation program is directed toward peak capacity and maximum energy use," the bulk of the conservation costs should be allocated to the peak season (winter). Id. Although conservation saves more energy in the winter season than the summer season, these savings benefit the system as a whole rather than consumers in any particular season. Id., 30; Wedlund/Emery, BPA, E-BPA-51, 13-14. NIU claims that because conservation is a unique resource, it should be seasonalized differently from other energy costs. Kavanaugh, NIU, E-NI-04, 29-30. However, NIU fails to demonstrate how these differences make it more efficient or fair to seasonalize conservation costs separately from other

energy costs. Wedlund/Emery, BPA, E-BPA-51, 13-14. BPA's method of seasonalizing energy costs treats the system as a whole, recognizing that all of BPA's resources--thermal, hydro, and conservation--are used as a combined system to meet total system load. Thus, it is inappropriate to treat conservation differently from the rest of the system. Id., 13.

Decision

It is appropriate to seasonalize conservation costs uniformly with other energy related costs, since all resources are used as a combined system.

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CHAPTER VI

SECTION 7(b)(2) RATE TEST

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a comparison of the projected rates to be charged its preference and Federal agency customers for their general requirements with the costs of power (hereafter called rates) to those customers if certain assumptions are made. 16 U.S.C. §839e(b)(2). The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) customers). The two sets of rates are: (1) a set for the test period and ensuing four years assuming that section 7(b)(2) is not in effect (program case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the program case rates. Next, each nominal rate is discounted to the test year of the relevant rate case. The discounted program case rates are averaged, as are the 7(b)(2) case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average program case rate is greater than the average 7(b)(2) case rate, the rate test triggers. Based on the extent to which the test triggers, the amount to be reallocated in the rate proposal test period is calculated.

The methodology to implement section 7(b)(2) was developed in a section 7(i) proceeding that preceded the 1985 rate case. The 7(i) process culminated in the Section 7(b)(2) Implementation Methodology Record of Decision (B-2-84-F-02). Issues requiring interpretation of the statute were resolved in the Legal Interpretation for Section 7(b)(2). 49 FR 23,998 (1984).

Issue 1

Should residential exchange subsidies paid to qualifying preference customers reduce the program case PF rate in BPA's 7(b)(2) rate test?

Evaluation of Positions

The IOUs, WUTC, and DSIs argue that because BPA has not adjusted the program case to reflect the benefits of the residential exchange to preference customers, BPA has overstated the average power costs actually paid by preference utilities. Initial Brief, PP&L/PGE, B-PL/GE-01, 3-5; Initial Brief, Puget et al., B-PS/MP/WP-01, 23; Initial Brief, WUTC, B-WU-01, 4-5; Initial Brief, DSI, B-DS-01, 26-28. The IOUs and WUTC argue that the

residential exchange will provide selected preference customers with a wholesale power cost credit equal to 1.1 mills per kilowatthour. Initial Brief, PP&L/PGE, B-PL/GE-01, 5; Initial Brief, WUTC, B-WU-01, 5. The IOUs and DSIs allege that recognition of preference customer exchange credits is equitable and conforms with the legislative purpose of section 7(b)(2) of the Northwest Power Act. Initial Brief, PP&L/PGE, B-PL/GE-01, 5-7; Initial Brief, DSI, B-DS-01, 26-27.

In Briefs on Exceptions, PP&L and WUTC argue that a 7(b)(2) surcharge has been imposed solely because BPA has refused to account for residential exchange benefits enjoyed by preference utilities in determining whether or not preference utilities as a group actually are disadvantaged by the Northwest Power Act. Exceptions, PP&L, R-PL-01, 1-3; Exceptions, WUTC, R-WU-01, 2. PP&L argues that BPA has failed to calculate the actual "projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and federal agency customers" as required by section 7(b)(2). Exceptions, PP&L, R-PL-01, 4. PP&L and WUTC also argue that the legislative history of the Northwest Power Act requires a different treatment of preference utility residential exchange benefits than proposed by BPA. Exceptions, PP&L, R-PL-01, 4-6; Exceptions, WUTC, R-WU-01, 3. Puget, WWP and MPC similarly argue that it is inappropriate for the amount of the public agency exchange to exceed the amount of the 7(b)(2) rate lid trip which BPA is proposing to use to protect public agency rates. Exceptions, Puget et al., R-PS/MP/WP-01, 24-25.

In oral argument, APAC objected to the arguments of the IOUs. Oral Argument, APAC, TR 3115. APAC argues that public agency exchange loads are not preference requirements loads and are not protected by section 7(b)(2). Id. All exchange loads place a cost burden on preference customers' requirements purchases. Id. The issue is not one of intraclass transfer, because requirements customers are burdened by the exchange whether it is public or private. Id. Finally, if residential exchange costs contribute to the 7(b)(2) trigger, this is consistent with the intent of section 7(b)(2). Id.

Public utilities also responded to the arguments of the IOUs, WUTC, and DSIs in their Briefs on Exceptions. PPC/APAC argues that altering the program case as suggested by nonpreference customers would violate section 7(b)(2) of the Northwest Power Act, the Administrator's 7(b)(2) Legal Interpretation, and the 7(b)(2) Implementation ROD. Exceptions, PPC/APAC, R-PA/PP-01, 1-5. PPC/APAC also argues that such a proposal would be inconsistent with the previous implementation of the rate test in BPA's 1985 rate case and would be inequitable and unfair to preference customers. Id. PNGC and PUD No. 1 of Cowlitz County similarly argue that the express language of the Northwest Power Act refutes the nonpreference customers' arguments. Exceptions, PNGC, R-PN-01, 3-4; Exceptions, Cowlitz, R-CO-01, 1-2. PNGC and Cowlitz also question the IOUs' argument that the 7(b)(2) surcharge is the result of the public agency exchange. Id.

The arguments of the IOUs, WUTC, and DSIs fail to focus on the statutory language governing the section 7(b)(2) rate test. Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. §839e(b)(2), provides:

> After July 1, 1985 the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers . . . may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator [makes specific assumptions]. (Emphasis added.)

The term "general requirements" as used in section 7(b)(2) is defined as "the public body, cooperative or Federal agency customer's electric power purchased from the Administrator under section 5(b) of this Act, exclusive of any new large single load." (Emphasis added.) 16 U.S.C. §839e(b)(4). Section 5(b) of the Northwest Power Act governs sales to preference customers and investor-owned utilities for their firm power needs. Section 5(c) of the Act, in contrast, governs sales to preference customers and investor-owned utilities under the residential exchange program. Section 5(c) sales are not "general requirements" sales.

The Northwest Power Act addresses "the projected amounts to be charged for the combined general requirements" of preference customers, not the amounts to be charged for the combined general requirements less the benefits to preference customers for qualifying residential exchange loads. It is inappropriate to include benefits from the public agency residential exchange in the amounts to be charged for only firm requirements loads.

The legislative history cited by the IOUs and DSIs does not demonstrate that preference customer exchange benefits should be used to reduce the amounts to be charged such customers for their general requirements. The cited legislative history discusses the basic purpose of the 7(b)(2) rate test: to assume that the preference customers' cost of power from BPA under the Northwest Power Act (program case) would not exceed their cost for power given certain specific assumptions (7(b)(2) case). The DSIs and IOUs argue that the 7(b)(2) calculation should protect preference customers from only the residential exchange payments to investor-owned utilities. Initial Brief, DSI, B-DS-01, 26; Initial Brief, PP&L/PGE, B-PL/GE-01, 6. This argument fails, however, since the cited legislative history addresses only the 7(b)(2) case, not the program case. See H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34, 68 (1980); H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). BPA agrees that exchange costs are to be removed from the 7(b)(2) case. The question, however, is whether exchange benefits of qualifying preference utilities should be used to reduce the amounts to be charged for preference general requirements loads in the program case. No legislative history cited by the parties directly addresses this issue. To the contrary, the plain language of the statute militates against such a conclusion.

PP&L and WUTC reiterate their citations to legislative history of the Northwest Power Act in their Briefs on Exceptions. Exceptions, PP&L, R-PL-01, 4-6; Exceptions, WUTC, R-WU-01, 3. PP&L and WUTC argue that the intent of section 7(b)(2) was that preference utilities would retain ". . . the price benefits of federal power that they would have enjoyed in the absence of this legislation." H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980).

PP&L argues that BPA's residential exchange payments to preference customers enhance the "price benefits of federal power" to preference utilities, but that Congress intended that the 7(b)(2) surcharge not be triggered by such payments. Exceptions, PP&L, R-PL-01, 5. PP&L cites legislative history which PP&L argues demonstrates an intent that the 7(b)(2) surcharge should be triggered by only those residential exchange costs associated with investor-owned utilities. See H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34, 68 (1980). While the cited excerpts reference only IOU exchanges, such a limitation is inconsistent with the plain language of the statute, as discussed above. In addition, these excerpts must be read in the complete context of the House Committee on Interstate and Foreign Commerce report. This report also states that "[s]ection 5(c) permits power exchange and power sales whereby rate relief will be provided residential customers of investor-owned utilities." H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 60 (1980). This statement is plainly at odds with the statutory language of section 5(c) which allows both investor-owned and publicly owned utilities to participate in the residential exchange. 16 U.S.C. §839c(c)(1). The House Commerce report refers only to investor-owned utilities in the excerpts cited by PP&L because, at that time in the development of the bill, the Committee viewed investor-owned utilities as the sole beneficiaries of the residential exchange. This is verified by additional language in the report which states that "[a]lthough all utilities are permitted to enter into such sales, its benefits are likely to be limited to utilities that are not entitled to service as a preference customer." Id. Since the committee report refers solely to an investor-owned utility exchange, the legislative history cited by the parties does not establish congressional intent that the section 7(b)(2) test could only be triggered by the exchange costs of investor-owned utilities. Rather, it simply reflects that the committee at that time was viewing the residential exchange program as related solely to investor-owned utilities. The ambiguous legislative history cited by PP&L and WUTC does not overcome the express statutory requirements of sections 7(b)(2) and 7(b)(4).

PP&L also argues that the impact of residential exchange payments to preference utilities "was to be neutralized by retaining the payments as costs in the '7(b)(2) case.'" Exceptions, PP&L, R-PL-01, 5. This argument is refuted by the express terms of the Northwest Power Act. Section 7(b)(2)(C) expressly requires the 7(b)(2) case to assume "no purchases or sales by the Administrator as provided in section 5(c)." 16 U.S.C. §839e(b)(2)(C). As noted by PPC/APAC, since the Act does not distinguish between IOU and preference exchange loads, preference customer general requirements must be held harmless from the entire exchange. Exceptions, PPC/APAC, R-PA/PP-01, 3-4.

The argument of PP&L, WUTC, and the DSIs is not only contrary to the statute, but also contrary to BPA's Legal Interpretation of Section 7(b)(2) (Legal Interpretation). The Legal Interpretation defines "7(b)(2) general requirements" to "include power purchased from BPA only under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included." Legal Interpretation, 49 FR 23,998 (1984). PP&L argues that this is true, but irrelevant since residential exchange benefits are rebates to charges for preference customers general requirements purchases. Exceptions, PP&L, R-PL-01, 7. PP&L's characterization of residential exchange benefits,

however, does not allow BPA to ignore the requirements of the 7(b)(2) Legal Interpretation.

PPC/APAC notes that the 7(b)(2) Implementation ROD states that "[t]he PF rate in the program case will be developed in the same manner as it is in BPA's rate proposal." Implementation ROD, B-2-84-F-02, 44; Exceptions, PPC/APAC, R-PA/PP-01, 1. PPC/APAC also notes that the Implementation ROD provides that "[t]he program case is the five-year projection of power costs for serving the general requirements of the 7(b)(2) customers." Implementation ROD, B-2-84-F-02, 39; Exceptions, PPC/APAC, R-PA/PP-01, 2. Therefore, argues PPC/APAC, BPA's proposal correctly provides that the program case mirrors the rate proposal. PPC/APAC also argues that the 7(b)(2) Legal Interpretation and the Implementation ROD constitute the law of the case which binds the Administrator. Id., 3.

While PP&L argues that this issue is one of first impression and that the preference customer exchange was a relatively minor matter prior to 1985, Exceptions, PP&L, R-PL-01, 7, it should still be noted that at no time during the development of the Legal Interpretation, the 7(b)(2) implementation methodology, or the 1985 rate case did the IOUs, DSIs or WUTC raise this issue.

The argument of the IOUs, WUTC, and DSIs also is not persuasive in light of the fact that the preference customers participating in the residential exchange are allocated part of the 7(b)(2) adjustment. PP&L argues that if preference customer benefits were properly accounted for, there would be no 7(b)(2) adjustment to allocate. Exceptions, PP&L, R-PL-01, 8. PPC/APAC, however, notes that public exchangers pay their share of the 7(b)(2) surcharge. Exceptions, PPC/APAC, R-PA/PP-01, 4.

Finally, preference customer residential exchange loads are served at the PF exchange rate, not the PF preference rate. PP&L argues that all preference customers receive their general requirements at the PF preference rate. Exceptions, PP&L, R-PL-01, 8. PP&L views the residential exchange transaction as a rebate to the general requirements sales rather than as a load served at the PF exchange rate. Id. PP&L ignores, however, that BPA establishes a PF preference rate for general requirements loads of preference customers, and a PF exchange rate for preference customer exchange loads. As noted by PPC/APAC, not all preference requirements customers benefit from the residential exchange. Exceptions, PPC/APAC, R-PA/PP-01, 7.

Decision

For purposes of conducting the 7(b)(2) rate test, BPA will not reduce the amounts to be charged preference customers for their general requirements in the program case for the benefits received by qualifying preference customers under the residential exchange. Such a reduction would conflict with the Northwest Power Act, BPA's Legal Interpretation, and the 7(b)(2) Implementation ROD.

Issue 2

Should the section 7(b)(2) rate test assume that preference customers refinanced the combustion turbines used for reserves in the 7(b)(2) case?

Evaluation of Positions

As outlined in the Section 7(b)(2) Implementation Methodology Record of Decision (Implementation ROD), reserve benefits are quantified in the 7(b)(2) case using the same analysis as is used in the relevant rate case. Implementation ROD, B-2-84-F-02, 9. The 1987 rate proposal uses the IP-PF rate link to develop rates. The link incorporates the value of reserves credit developed in the 1985 rate proceeding. BPA, E-BPA-06, 42-43. Therefore, reserve benefits for the section 7(b)(2) rate test are quantified using the results of the value of reserves (VOR) analysis from the 1985 rate case. Armstrong/Parker, BPA, E-BPA-50, 4-5. The VOR analysis assumes that BPA would have acquired combustion turbines (CTs) for reserves in 1982 if restriction rights on the DSI loads were not available. Interest rates were very high in 1982; BPA assumed that the CTs were financed by issuing bonds at 14 percent. Id. The DSI restriction rights were valued in large part at the annual investment and O&M costs of the CTs. The full value of reserves adjusted by the results of a financing benefits analysis and the "within and adjacent" level of DSI service is used as the amount of reserve benefits in the 7(b)(2) case. Id.

PPC/APAC argues that hypothetical bonds issued in 1982 at high interest rates for CTs should be assumed to be refunded, which would lower the cost of reserves to 7(b)(2) customers in the 7(b)(2) case. Drummond/Wolverton, PPC/APAC, E-PA/PP-01, 3-6. They argue that interest rates have decreased since 1982 and utilities have financed advance refundings of long-term bonds they sold during the earlier high interest rate period. Id.

PPC/APAC is correct in noting that interest rates have fallen and created opportunities for refinancing; however, such an assumption for determining reserve benefits for the 7(b)(2) case would create an inconsistency in the 7(b)(2) rate test methodology. The Legal Interpretation states the basic assumption for implementing the rate test: the program case and 7(b)(2) case shall be the same with the exception of the assumptions in sections 7(b)(2)(A)-(E) of the Northwest Power Act, 16 U.S.C. §839e(b)(2). 49 FR 23,998 (1984). A reflection of this basic premise is the statement in the Implementation ROD that BPA "will quantify reserve benefits in the 7(b)(2) case by using the same analysis as is used in the relevant rate case." Implementation ROD, B-2-84-F-02, 9.

The IP-PF rate link is used to determine the 1987 rates; thus, it is used in the program case of the 7(b)(2) rate test. The link effectively fixes the value of reserves, adjusting only for inflation. Therefore, an inconsistency would be created between the two cases by assuming bond refunding in the 7(b)(2) case, but maintaining the fixed values in the program case. Such a discrepancy would be in direct contradiction of the Legal Interpretation and the Implementation ROD. Armstrong/Parker, BPA, E-BPA-50, 5; Initial Brief, PP&L/PGE, B-PL/GE-01, 23. As pointed out by PP&L/PGE, if the refinancing

assumption recommended by PPC/APAC were implemented, there would be simultaneous assumptions of a larger value of reserves for the program case and a smaller value of reserves for the 7(b)(2) case. Initial Brief, PP&L/PGE, B-PL/GE-01, 24-25. This inconsistent combination would produce a higher 7(b)(2) surcharge than either a high or low assumed value of reserves, used consistently. Id.

PPC/APAC argues that implementation of the IP-PF rate link is unrelated to the "accurate" implementation of the 7(b)(2) rate test. PPC/APAC contends it would not have supported the link had it been aware of its consequential use in the rate test. Initial Brief, PPC/APAC, B-PA/PP-01, 4. However, the implementation of the IP-PF rate link is necessarily related to the implementation of the 7(b)(2) rate test because (1) the program case models the rate case; and (2) the 7(b)(2) case is the same as the rate case with the exception of the assumptions in sections 7(b)(2)(A)-(E) of the Northwest Power Act. 49 FR 23,998 (1984). At the time PPC and APAC decided to support the IP-PF rate link, the Legal Interpretation and the Implementation ROD had been available for at least 2 years.

PPC/APAC points out that the 7(b)(2) test recognizes the difference in the cost of capital to the publics and to BPA for the acquisition of CTs. Exceptions, PPC/APAC, R-PA/PP-01, 506. They argue that since BPA recognized this difference, BPA should also assume that the CTs were refinanced. Id., 6. However, recognition of a difference in initial financing costs did not create an inconsistency between the two cases. In the Implementation ROD, BPA stated that the financing difference "tracks in the 7(b)(2) case the same methodology (albeit using a different interest rate) used in the relevant rate case." Implementation ROD, B-2-84-F-02, 9. However, PPC/APAC recommends introducing an assumption in the 7(b)(2) case that does not track the methodology in the rate case: due to the IP-PF rate link, BPA cannot assume refinancing in the program case.

PPC/APAC suggests that the refinancing assumption would allow BPA to use more accurate data in implementing the rate test. Initial Brief, APAC/PPC, B-PA/PP-01, 4. They also point out that refinancing of high interest rate bonds by public utilities in the region has occurred and, thus, one need not speculate in order to assume refinancing. Id., 5-6; Exceptions, PPC/APAC, R-PA/PP-01, 06. PP&L/PGE, however, demonstrate that the refinancing proposal would be highly speculative. Initial Brief, PP&L/PGE, B-PL/GE-01, 24. For example, speculation would exist regarding the timing of the refinancing and the number of times it would occur. Id. These factors would affect the level of underwriters' fees and the issuance cost. Id.

Regardless of whether advanced financing has actually occurred, it is not an appropriate assumption for the 7(b)(2) rate test. The rate test is not an exercise in speculating what rates would be without the Act. It is designed to protect the preference customers from certain possible adverse effects of the Act on their rates. The Act specifies the assumptions to be made in implementing the rate test. Further interpretation and implementation methods have been established by BPA. As discussed above, a refinancing assumption would be contrary to both the Legal Interpretation and Implementation ROD.

Decision

The 7(b)(2) rate test does not assume refunding of CT bonds in determining the cost of reserves in the 7(b)(2) case, since doing so would create an inconsistency between the program case and 7(b)(2) case. This inconsistency would be contrary to the 7(b)(2) Legal Interpretation and the Implementation ROD.

Issue 3

Should conservation costs be added to the 7(b)(2) case?

Evaluation of Positions

BPA excludes all conservation costs from the 7(b)(2) case. All conservation costs are considered resource costs for which load reductions are identified, and are thus excluded from the 7(b)(2) case until such time that FBS resources are insufficient to serve the 7(b)(2) customers' loads. Armstrong/Parker, BPA, E-BPA-50, 2-3.

The IOUs contend that a major portion of conservation costs should be included in the 7(b)(2) case rates. Brattebo et al., IOU, E-IO-01, 5-9. PP&L/PGE argues that failure to include certain conservation costs in the 7(b)(2) case: (1) would be inconsistent with the Northwest Power Act requirement that the 7(b)(2) case resemble the program case except when specific differences are mandated; (2) would be inconsistent with the treatment of analogous generation costs; (3) would be inconsistent with the standards for inclusion of costs as articulated by BPA's witnesses; and 4) would be inequitable because in such event necessary costs not related to specific resources never would be included in the 7(b)(2) case. Initial Brief, PP&L/PGE, B-PL/GE-01, 13.

PP&L/PGE argues that failure to include conservation costs in the 7(b)(2) case would be inconsistent with the Northwest Power Act requirement that the 7(b)(2) case resemble the program case except when specific differences are mandated. Initial Brief, PP&L/PGE, B-PL/GE-01, 13. BPA agrees that the two cases should be the same except for mandated differences. The Legal Interpretation states that "Section 7(b)(2) requires BPA to assume that the section 7(b)(2) case is identical to the program case except for those differences required by the five assumptions set out in section 7(b)(2)(A)-(E)." (Footnote omitted.) 49 FR 23,998 (1984). Section 7(b)(2)(B) requires that the 7(b)(2) customer loads should be served with FBS resources. 16 U.S.C. §839e(b)(2)(B). When FBS resources are no longer sufficient to serve this load, section 7(b)(2)(D) sets forth the assumptions to be used to determine the additional required resources and their cost. 16 U.S.C. §839e(b)(2)(D). This is confirmed in BPA's Legal Interpretation and the Implementation ROD. Armstrong/Parker, BPA, E-BPA-50, 7.

FBS resources are sufficient to serve the 7(b)(2) customers' loads through the end of the rate test period. No other resources are required. When additional resources are required, conservation resources will be considered.

Id., 8. It is inappropriate to include conservation costs, however, when conservation may not be the resource used to meet 7(b)(2) customers' loads after the FBS becomes insufficient. PPC/APAC agrees that there is no requirement set forth in the Legal Interpretation that conservation is the next resource used to serve public agency loads should the FBS be insufficient. Initial Brief, PPC/APAC, B-PA/PP-01, 7-8. Since the FBS is sufficient to serve 7(b)(2) customers' loads in this rate case, the addition of conservation or other resources need not be determined. Id; Exceptions, PPC/APAC, R-PA/PP-01, 6-7.

PP&L/PGE argues that the exclusion of conservation costs from the 7(b)(2) case would be inconsistent with the treatment of analogous generation costs. Initial Brief, PP&L/PGE, B-PL/GE-01, 13. The IOUs contend that conservation costs are no different than Washington Nuclear Project (WNP) or resource acquisition costs that are included in the 7(b)(2) and program cases but are not associated with current power production. Brattebo et al., IOU, E-IO-01, 8-9.

The fact that two of the three WNP plants are not producing power is unrelated to their treatment in the 7(b)(2) rate test. WNP plants are FBS resources by definition; section 7(b)(2)(B) of the Northwest Power Act states that FBS resources should be allocated to the 7(b)(2) customers in both the 7(b)(2) and program cases. Resource acquisition costs are not included in the revenue requirement for the term of the 7(b)(2) rate test period in the program and 7(b)(2) cases. Any costs included in the revenue requirement relating to research and planning of resources are not associated with specific resources. Armstrong/Parker, BPA, E-BPA-50, 3. Therefore, no inconsistencies exist regarding the treatment of conservation costs in relation to generation costs.

PP&L/PGE contends that exclusion of conservation costs from the 7(b)(2) case would be inconsistent with the standards for inclusion of costs as articulated by BPA's witnesses. Initial Brief, PP&L/PGE, B-PL/GE-01, 10-11, 13. The cited standard states: " . . . to the extent the [conservation] activity results in actual acquisition of resources or some construction of resources, those costs would be treated in a manner consistent with the 7(b)(2) interpretation and methodology. To the extent they are strictly planning and development with no generation expected to result from them, then they would be generic costs that would be included in both cases." Armstrong, BPA, TR 26-27. The IOUs argue that three general categories of conservation costs are not acquisitions and should be included in the 7(b)(2) case. The three categories are: Model Conservation Standards (MCS), General Support, and Other Industrial. Initial Brief, PP&L/PGE, B-PL/GE-01, 12-13.

According to BPA's Draft 1987 Resource Strategy (see Initial Brief, PP&L/PGE, B-PL/GE-01, 10-11) "Savings from the MCS are assumed to be Bonneville's first-priority conservation resource because they provide savings that last well into the deficit period." (Official notice.) Draft 1987 Resource Strategy, BPA, December 1986, II-3. In this same document, "General Support" (which includes conservation research and development) is described as "activities which provide support to conservation acquisitions through improving reliability of resource estimates, measuring actual program

performance, and enhancing program implementation." (Emphasis added.) Id., II-5. The "Other Industrial" category is the Industry-Initiated Program that will pay an incentive for conservation measures designed by non-DSI industries. Obviously, a conservation resource is expected from this program. All conservation expenditures that the IOUs want to include in the 7(b)(2) case are designed to result in conservation resources, or are necessary to support such programs. Armstrong, BPA, TR 33; Exceptions, PPC/APAC, R-PA/PP-01, 7. Thus, the exclusion of these conservation costs from the 7(b)(2) case is consistent with the standards for inclusion of costs as articulated by BPA witnesses.

PP&L/PGE argues that "BPA nonacquisition costs" should be included in the 7(b)(2) case. Initial Brief, PP&L/PGE, B-PL/GE-01, 11-13. However, the terms "acquisition" and "nonacquisition" as used in BPA's Resource Strategy are a modeling distinction only. Specifically, these terms refer to the different modeling approaches used in representing costs and savings of BPA's conservation programs. The term "acquisition" is applied to all conservation programs for which (1) BPA controls the rate at which the conservation resource is acquired (1987 Resource Strategy, May 1987, V-4, 5), and (2) the individual program expenditures can be precisely quantified and directly linked to a specific amount of energy savings from an individual program. The term "nonacquisition" applies to (1) a conservation program effort for which BPA does not control the rate at which the conservation resource is acquired; for example, the Con/Mod and MCS programs (Id., 5); and (2) "general support" programs which provide support to conservation acquisition activities (Draft 1987 Resource Strategy, December 1986, II-3). Thus, all conservation expenditures, whether identified as acquisition or nonacquisition, are designed to result in conservation resources.

BPA has not identified any conservation costs that do not result in acquisition of a resource. Armstrong, BPA, TR 33. If such costs were identified, however, they would be no different than other costs not associated with resource output that are included in both the program and 7(b)(2) cases. Redefining these costs as being distinct from conservation savings would indicate that they should no longer be characterized as conservation costs in the context of the enumerated section 7(g) costs that are removed from the PF rate. Therefore, they would not be removed from the PF rate before comparison with the 7(b)(2) rate.

Although PP&L/PGE argues that BPA should respect the standard for including conservation costs in the 7(b)(2) case as articulated by BPA during cross-examination, they do not consider this standard wholly adequate. The IOUs and WUTC argue that regardless of the fact that conservation resources are being acquired through implementation of a program, the reasons for making conservation expenditures and acquiring conservation resources must be examined. The IOUs amd WUTC label each conservation program included in BPA's 1986 Draft Workplan as: lost opportunity, research, equity, or economic development. Brattebo et al., IOU, E-IO-01, 6-9; Initial Brief, WUTC, B-WU-01, 6. They argue that the cost of any program thus labeled should be included in the 7(b)(2) case because it is undertaken for reasons other than to acquire conservation resources. Based on the observation that a considerable surplus exists in both the program and 7(b)(2) cases, the IOUs

argue that most conservation expenditures are unrelated to the need for additional resources. Id.

The IOUs have set forth two standards for including conservation costs in the 7(b)(2) case: (1) the conservation expenditure does not result in acquisition of a resource, and (2) the conservation expenditure is made during a surplus period for reasons other than to acquire conservation resources, regardless of whether conservation resources are achieved. In fact, the IOUs' application of these two standards is contradictory. For example, the standard of scrutinizing the reason the conservation expenditure is made results in less than one percent of the weatherization program cost being properly excludable from the 7(b)(2) case. Brattebo et al., IOU, E-IO-01, 7-9, Exhibit 3. However, PP&L/PGE states that the proposed acquisition/capability building program levels, with the exception of Other Industrial, may be excluded from the 7(b)(2) case. Initial Brief, PP&L/PGE, B-PL/GE-01, 12-15. Since acquisition/capability building includes weatherization programs, it is unclear what the IOUs consider properly excludable from the 7(b)(2) case and what is not, and what standard should be used to make this determination. PPC/APAC agrees that the IOU's proposal is internally inconsistent and unworkable. Exceptions, PPC/APAC, R-PA/PP-01, 7.

In addition, BPA's load/resource balance is based on the assumption that programs that result in conservation savings will be adopted. That is, conservation savings due to MCS, Con/Mod, weatherization, and other programs are subtracted from the forecasted loads in determining the load/resource balance. BPA, E-BPA-03A1, 43; Sugiyama/Spies, BPA, E-BPA-45, 1. Therefore, the amount of forecasted surplus power is a function of the conservation program. Also, although lost opportunities, research, equity, and economic development are indeed considerations in designing and implementing conservation programs, they are not the primary objectives of the conservation programs. The objective of conservation programs is to acquire, or build infrastructure to acquire, conservation resources. Thus, the IOUs' standards for determining which conservation costs are includable in the 7(b)(2) case are not clearly delineated, are internally contradictory, and ignore the nature of BPA's conservation programs.

BPA's conservation program has been set up to carry out the directives of the Northwest Power Act. 16 U.S.C. §839d(e)(1). All of BPA's conservation expenditures are geared to acquiring conservation resources. Conservation resources must often be acquired before they are needed to prevent their becoming lost opportunities. The fact that BPA may not have the same control over the timing of conservation resources as it would over a coal plant does not negate its value as a resource acquisition. For example, the amount of savings achieved from the MCS program is dependent on the rate of new electrically heated homes or commercial buildings constructed in the region. The level of construction activity is driven by macroeconomic factors such as population and employment levels that are outside of BPA's control. These are factors that must be considered when designing and implementing conservation resources programs. All conservation expenditures are made to enable BPA to acquire cost-effective conservation resources. Section 7(b)(2) defines the standard by which the need for new resources is determined and what resource costs should be included in the 7(b)(2) case. Therefore, since conservation

expenditures are made to acquire conservation savings, other considerations for the timing of the acquisition of the conservation savings in the program case such as equity or economic development are irrelevant to the implementation of the rate test.

PP&L/PGE also argues that exclusion of conservation costs from the 7(b)(2) case would be inequitable because necessary costs not related to specific resources never would be included in the 7(b)(2) case. Initial Brief, PP&L/PGE, B-PL/GE-01, 13. This issue is not ripe, however, since FBS resources are sufficient to serve the 7(b)(2) customers' loads. Therefore, the type and cost of required additional resources is not yet at issue.

WUTC argues that it is improper to exclude all conservation costs from the 7(b)(2) case because BPA had authority to invest in conservation prior to the Oct, and in fact made such investments. Initial Brief, WUTC, B-WU-01, 5-6. This argument is directly rebutted by the legislative history of the Northwest Power Act. The report of the House Committee on Interstate and Foreign Commerce states: "BPA has limited authority to carry out conservation programs, and no authority to borrow or underwrite funds to finance these programs." H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 26 (1980). Similarly, the report of the House Committee on Interior and Insular Affairs states that "[t]he ability of BPA to carry out these conservation programs is also limited since its authority to engage in these activities is minor and since it cannot borrow funds to finance their implementation." H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 31 (1980). Indeed, a primary purpose of the Act is "to encourage . . . conservation and efficiency in the use of electric power." 16 U.S.C. §839(1). The argument that conservation investment would have been made by BPA in the absence of the Act is highly speculative, unsupported by the legislative history of the Act, and inconsistent with BPA's Legal Interpretation.

WUTC also states that conservation investment may raise per-unit rates, but reduce the total cost of power to preference customers. Initial Brief, WUTC, B-WU-01, 6-8. WUTC further states that the Northwest Power Act is silent on which measure of impact--total cost or average rate--on preference customers should be applied in determining the trigger. WUTC ignores the Implementation ROD, in which the issue of determining the trigger was evaluated and decided. Implementation ROD, B-2-84-F-02, 32-33, 44-45. The Implementation ROD provides that "the rate test model will produce a projection of annual average energy rates" that "will be compared." Id., 44.

Decision

Conservation costs will not be added to the 7(b)(2) case while the FBS is sufficient to serve the 7(b)(2) customers' loads. BPA conservation expenditures are directly related to the acquisition of conservation resources.

Issue 4

What is the effect on DSI loads of removal of the Conservation/ Modernization (Con/Mod) program from the 7(b)(2) case?

Evaluation of Positions

BPA initially included the same DSI loads in both the program and 7(b)(2) cases. Sugiyama/Spies, BPA, E-BPA-33, Attachment C. The IOUs suggested that, since costs of the Con/Mod program were included in the program case and excluded from the 7(b)(2) case, the savings attributable to the Con/Mod program should be removed from the 7(b)(2) case. Brattebo et al., IOU, E-IO-01, 8. BPA concluded that this argument is correct in concept, but loads should not be lower in the 7(b)(2) case as suggested by the IOUs; rather, they should be adjusted upwards. Sugiyama/Spies, BPA, E-BPA-45, 1.

PP&L/PGE asserts that the upward adjustment to 7(b)(2) case loads is incorrect. Initial Brief, PP&L/PGE, B-PL/GE-01, 14. Specifically, PP&L/PGE asserts that removal of the Con/Mod program from the 7(b)(2) case should result in a downward adjustment to loads due to the expectation that the Con/Mod program would prevent plant closures. Initial Brief, PP&L/PGE, B-PL/GE-01, 14; Exceptions, PP&L/PGE, R-PL-01, 9. Further, PP&L/PGE claims that the adjustment made by BPA in rebuttal is inconsistent with the analysis for the Con/Mod program in the Administrator's Record of Decision for the Con/Mod program. Id.

PPC/APAC supports BPA's calculation of the effect of the Con/Mod program. Exceptions, PPC/APAC, R-PA/PP-01, 8. PPC/APAC argues that improved market prices make plant closures less likely. Id.

Section 7(b)(2)(B) effectively requires that the 7(b)(2) case be developed under the assumption that there is no Con/Mod program. 16 U.S.C. §839e(b)(2)(B). In removing the effects of the Con/Mod program on DSI loads, BPA assumed no additional plant closures would occur in the 7(b)(2) case if none were assumed for the program case. Armstrong, BPA, TR 36-38. Therefore, the DSI load in the 7(b)(2) case was higher than that in the program case due to the lack of efficiency gains without the Con/Mod program. Sugiyama/Spies, BPA, E-BPA-45, Attachments 1 and 2.

PP&L/PGE argues that the rationale for instituting the Con/Mod program was to avoid plant closures that seemed probable given the economic conditions at that time. Had there been no Con/Mod program, it is possible that plant closures would have occurred. The economic condition of the aluminum industry in recent years persuaded BPA to offer the Con/Mod program as part of an overall plan to stabilize DSI loads. PP&L/PGE argues that the decision to implement the Con/Mod program was made in order to maintain DSI load, thus stabilizing BPA revenues and helping to keep other BPA customers' rates low. Initial Brief, PP&L/PGE, B-PL/GE-01, 14-15. In the DSI Options Study, BPA concluded that the Con/Mod program would enable the DSIs to "become more competitive in the world aluminum market," which would enable them "to survive economic downturns and operate at higher levels of plant capacity." During surplus periods, "BPA's revenues would therefore be stabilized and possibly enhanced." DSI Options Study, Final Report - Part 1, June 1985, 35. Given the recent depressed economic conditions, it is quite possible that some smelters would have closed without the Con/Mod program, current healthy market conditions notwithstanding. Indeed, three smelters have closed within the past 3 years, one of which has reopened, one is expected to reopen, and one is

questionable. Sugiyama/Spies, E-BPA-45, Attachment 1. The recent robust response to the Con/Mod program offer (all 10 smelters have indicated interest) indicates the value of the program to smelter operations. This response was anticipated by the DSIs. Oral Argument, DSI, TR 2924. In fact, the current strength in the PNW aluminum industry may be due, in part, to the Con/Mod program. Smelter closures that have occurred in other producing regions may have been avoided in the PNW due to BPA's efforts, of which the Con/Mod program was a part.

PP&L/PGE points out that the model used to forecast DSI load in the Con/Mod proceedings addressed variation in the loads due to uncertainty. The Aluminum Smelter Model (ASM), used to forecast DSI loads for the rate case, does not explicitly address these factors. The ASM does not have the capability to predict smelter closures. Sugiyama/Spies, BPA, TR 1976. The ASM forecasts, with the assumption of no additional plant closures, had seemed appropriate given the deterministic nature of the 7(b)(2) rate test and the relatively positive near-term economic conditions forecasted for the DSIs. However, the results of the Decision Analysis Model (DAM) support an assumption of fewer smelter closures and higher smelter loads with the Con/Mod program. The DAM, which does have plant closure logic and examines a wide range of future scenarios, was used to conduct the analysis for the Con/Mod 6(c) process.

PP&L/PGE's arguments are persuasive that it is more appropriate to review the results of the DAM which has plant closure logic, given the economic conditions which inspired the institution of the Con/Mod program, than to assume no closures at all. Using the DAM analysis as the basis for the Con/Mod adjustment to the 7(b)(2) case DSI loads allows BPA to reflect the fact that the Con/Mod program has increased the probability that DSI plant closures would not occur, and fully remove the impact of the Con/Mod program from the 7(b)(2) case as required by section 7(b)(2)(B). Forecasted near-term economic conditions do not change the effect of the Con/Mod program on DSI plant viability. On the basis of the DAM analysis results, some smelter capacity would be expected to permanently close without the Con/Mod program. Specifically, the DAM analysis, as provided in testimony for the section 6(c) hearings, indicates an expected value of approximately 250 MW of smelter load that would be closed without the Con/Mod program. Record of Decision, BPA, DSC-6(c)-F-02; Opening Brief, Joint Parties, DSC-6(c)-B-JP-01, 4. The 250 aMW load reduction would be spread equally across the five smelters considered "at risk" during the development of the Variable Industrial Rate and Options Study: Troutdale, Vancouver, Mead, The Dalles, and Columbia Falls. Moorman/Spies, BPA, VI-86-E-BPA-08R, 13; Electric Power Rates for the Aluminum Industry in the PNW, Resource Strategies Inc., 1984, p. 53.

Decision

The DSI loads in the 7(b)(2) case are reduced by a total of 250 aMW to reflect BPA's estimate of the expected value of smelter closures without the Con/Mod program. The 250 aMW load reduction in the 7(b)(2) case is spread equally across the five smelters considered "at risk": Troutdale, Vancouver, Mead, The Dalles, and Columbia Falls.

Issue 5

What level of ISC should be included in determining revenue requirements through FY 1993 for the purpose of performing the 7(b)(2) rate test?

Evaluation of Positions

In both the initial and supplemental studies, BPA included $60 million of ISC in determining revenue requirements for FY 1988 and 1989. Roberts, BPA, E-BPA-15, 58; Roberts, BPA, E-BPA-35, 4. For purposes of performing the 7(b)(2) study, $60 million was also included for each year over the period FY 1990 through 1993. Roberts, BPA, E-BPA-47, 9. This amount of ISC was included in both the program case and the 7(b)(2) case. Id.

The IOUs cite various financial risks faced by BPA and propose that, for purposes of performing the 7(b)(2) test, BPA should include $120 million in ISC during FYs 1989 through 1993 in both the program case and the 7(b)(2) case. Brattebo et al., IOU, E-IO-01, 13-14. The IOUs identify specific risks including BPA's current financial difficulties, the risk of FY 1988 net revenue shortfalls, the risk of aluminum smelter closures, and the risk that repayment reform measures may be imposed on BPA's method of repayment. Id. This position was reiterated by PP&L/PGE as a means to account for the risk of a rate surcharge at the end of FY 1988 (see Chapter III. F.) and additional uncontrollable risks which could arise throughout the 7(b)(2) period. Initial Brief, PP&L/PGE, B-PL/GE-01, 18-19. PP&L/PGE further argues that the $60 million in ISC through FY 1993 for the 7(b)(2) rate test is too low because it results in a decreasing amount of coverage relative to planned amortization payments even though a fairly constant amount of coverage relative to net interest expense exists over that period. Id., 19.

Increasing ISC to $120 million over the FY 1989 to 1993 period would assume an overall risk management strategy different from that proposed for the FY 1988-89 rate period. Roberts, BPA, E-BPA-47, 10. In addition, as described in the Implementation ROD, the outyears of the 7(b)(2) rate test are modeled using the same methodology as in the rate case (Implementation ROD, B-2-84-F-02, 39-40), including the risk management package. This includes the ISC as well as the use of 1939 water conditions to calculate nonfirm energy revenues. Since the Supply Pricing Model is a deterministic model and the rate test is conducted in a deterministic manner, there is no reason to speculate on the outcome of certain events, such as the triggering the Cost Recovery Adjustment Clause. Armstrong/Parker, BPA, E-BPA-50, 6. PPC/APAC also objects to the IOUs' argument to increase the level of ISC to $120 million for FY 1989 through 1993. They argue that all of BPA's revenue requirement component projections, including ISC, are properly estimated without an expected value analysis. Drummond/Wolverton, PPC/APAC, E-PA/PP-02, 6-7; Exceptions, PPC/APAC, R-PA/PP-01, 8-9.

The concerns expressed by the IOUs with respect to unknown risks through the 7(b)(2) period may be valid. However, BPA cannot account for all such risks. In conducting the Risk Assessment Analysis used in development of BPA's risk management strategy, BPA limited its analysis to major identifiable risks during the rate period (see Chapter III. B. 2.). As part of the risk

management strategy proposed by BPA, $60 million of ISC was included in determining revenue requirements, consistent with a goal of improving the financial position of the FCRPS. Consistent with this goal and BPA's overall risk management strategy, the amount of ISC was held constant at $60 million through FY 1993. In response to parties' concerns over the current economic situation in the Pacific Northwest, the Administrator has reduced the level of ISC for FY 1988 and 1989 in an effort to reduce the upward pressure on the initial rate increase (see Chapter III. E. Issue 2).

However, the fact that the level of ISC is reduced does not mean that the level of risk faced by BPA is reduced or that BPA has relinquished its goal of improving its financial position. In the context of risk management, $60 million in ISC is still viewed as a prudent amount. In addition, as the IOUs note, BPA's planned amortization payments increase through the 7(b)(2) period. Initial Brief, PP&L/PGE, B-PL/GE-01, 19. The level of ISC was reduced during the FY 1988-89 rate period primarily due to current economic considerations and the upward pressure on the FY 1988-89 rate levels, not due to a reduction in the overall level of risk faced by BPA or the desired level of protection. Therefore, continuation of the $60 million in ISC proposed by BPA in FY 1990 through 1993 period is warranted.

Decision

For FY 1990 through 1993, ISC of $60 million will be included for both the 7(b)(2) case and the program case. The level of ISC for FY 1988 and 1989 has been reduced to $39.3 million and $49.8 million, respectively (see Chapter III. E. Issue 2).

Issue 6

Should the calculation of the Z-factor for OY 1939 use a 42-month critical generation mean?

Evaluation of Positions

The Z-factors in the 7(b)(2) rate test are parameters that partially define the distribution of availability of nonfirm energy during OY 1939 and over the 40 historical water years of record. In calculating the Z-factors, the critical generation mean is used. This term refers to the minimum amount of nonfirm energy available during the period being analyzed. Armstrong, BPA, TR 13. BPA calculates a Z-factor for the 40 water years using a critical generation mean term based on the average nonfirm energy availability during the 42-month critical period; and for OY 1939 using a critical generation mean based on the lowest monthly amount of nonfirm energy availability in that year, which is zero. Armstrong/Parker, BPA, E-BPA-50, 7-8.

The Z-factor calculation for the 40 water years assumes that the distribution of the number of occurrences of different levels of nonfirm energy available on a monthly basis is described by a log normal distribution. Armstrong/Parker, BPA, E-BPA-37, 7-8; Armstrong, BPA, TR 12.

The 40-year critical period is institutionally defined as a specific 42-month period; thus, the critical generation mean is based on this 42-month period. Id. In calculating a Z-factor for OY 1939 water conditions, it is again assumed that a log normal distribution adequately describes the distribution of monthly amounts of nonfirm energy within the year. Id. Therefore, the month that has the lowest nonfirm generation is defined as the critical period for OY 1939. Id. Since several months of OY 1939 show no nonfirm generation, the critical generation mean used in calculating the Z-factor for OY 1939 water condition is zero. Id. PPC/APAC agrees that the choice of the month with the lowest generation mean is an appropriate approach. Exceptions, PPC/APAC, R-PA/PP-01, 9.

The IOUs argue that the critical generation mean used for calculating the Z-factor for OY 1939 should be the same as that used for the 40 water year period Z-factor; namely, the 42-month critical period generation mean. Yu/Johnson, IOU, E-10-07SR, 5-7; Initial Brief, PP&L/PGE, B-PL/GE-01, 22. They state that the 42-month critical period is the basis for developing the critical rule curves. Id. These rule curves are the bases for determining the 40 years of data used in the Z-factor calculation. Id. The IOUs argue that since only one critical period has been used to derive the data, there should be only one value for the critical generation mean. Id. That value should be the one based on the 42-month critical period. Id.

As stated by the IOUs, critical rule curves are the bases for the 40 years of data that show nonfirm energy availability. The critical rule curves result from hydroregulation studies that optimize hydro generation under critical water conditions. These critical rule curves are one set of inputs used to derive the monthly availability of nonfirm energy for each of the 40 water years, 1929-1968, that are used in the Secondary Energy Analysis. BPA, E-BPA-03, 15-16.

These monthly amounts of nonfirm energy from the Secondary Energy Analysis are used in the Z-factor calculations. Armstrong/Parker, BPA, E-BPA-37, Attachment C, 14. Once the monthly amounts of nonfirm energy are determined, it is irrelevant that they are based on an assumption of critical or other water conditions in calculating the Z-factor. It is the derived nonfirm data that the Z-factor is attempting to describe. How the data are derived is not important in the calculation of the Z-factor; it is important that the Z-factor model the variability of the given data adequately. Armstrong, BPA, TR 14-16. The IOUs argue that an inconsistency is created by defining the critical generation mean differently for the 40-year average and OY 1939 water conditions. Initial Brief, PP&L/PGE, B-PL/GE-01, 21. Since the critical generation mean is defined as the minimum amount of available nonfirm energy, using the 42-month critical period average may be inconsistent with using the log normal distribution to describe the monthly variation in nonfirm energy availability. Armstrong, BPA, TR 15-16. The amount of available nonfirm energy is actually as small as zero in some months, and not the 378 aMW derived using the 42-month critical period average. Armstrong/Parker, BPA, E-BPA-37, Attachment C, 14.

Decision

The least amount of nonfirm energy during any month of the period being analyzed is used to determine the Z-factor for the 40 water years and OY 1939 water conditions. For both periods, the least amount of available nonfirm energy is zero. This method of determining the critical generation factor adequately captures the variability of nonfirm energy availability and eliminates any inconsistency in the application of this methodology to the two periods.

CHAPTER VII

COST ALLOCATION

A. Seasonalization of Energy Costs

Issue

How should BPA seasonally differentiate energy costs?

Evaluation of Positions

All energy costs in BPA's rate development process are seasonally differentiated based on the summer and winter seasonal splits developed for the FBS resource pool. FBS energy costs are seasonally differentiated in a two-step process. First, the energy seasons are determined based on monthly withdrawals from storage. Then costs are apportioned to seasons. Storage costs are assigned to the seasons based on energy produced from storage in each season. All other energy costs are apportioned to the winter and summer seasons according to projected firm energy generated by the FBS in each season, excluding May. BPA, E-BPA-06, 10-11.

NIU claims that BPA's method for seasonally differentiating energy costs does not adequately reflect the seasonal variation in energy costs. Kavanaugh, NIU, E-NI-04, 19. NIU argues that BPA's method understates the cost of hydro storage by ignoring thermal costs which are incurred throughout much of the year in lieu of using the energy that is being stored. Id., 20. NIU argues that stored hydro is valuable because it displaces the operation of combustion turbines. Id., 21. The benefits of such displacement are maximized when hydro is dispatched to displace as much of the high running-cost units as possible. Id. NIU calculates a value for hydro resources displacing higher cost resources through the Least Cost Mix Model (LCMM). Id., Attachment C, 3. The value from hydro used to displace higher cost resources is seasonalized into fall, winter, and summer seasons. NIU then calculates an imputed monthly cost of hydro resources, and applies such monthly imputed hydro costs to hydro production from storage in much the same manner as is done in BPA's method. Id., Attachment C, 4. NIU suggests that the result from such a calculation, which attributes 70 percent of FBS costs to winter and 30 percent to summer, should be used as BPA's seasonal differentiation of energy costs between winter and summer. Id., 26.

WPAG argues that NIU's method fails to consider a number of salient points about the Federal hydro system. McGary et al., WPAG, E-WA-03, 22. WPAG points out that the dams were sized, in part, upon considerations unrelated to energy production such as flood control, navigation, and irrigation. Id. Further, claims WPAG, hydro storage is undertaken for purposes other than satisfying winter loads, such as recreation, irrigation, and navigation. Id., 23. WPAG argues that it is incorrect to assume that hydro storage is undertaken to meet winter loads for valuing storage energy on the basis of displaced thermal costs. Id.

WPAG also argues that NIU is incorrect in asserting that thermal resources are run in the summer to facilitate hydro storage. Id. WPAG notes that thermal maintenance generally takes place in the period of April through June and that most hydro storage occurs during the months of March through July. Id. WPAG asserts that the period of least thermal generation is the period of maximum storage buildup. Id.

WPAG argues that the NIU method for allocating hydro storage costs to seasons is flawed. Id., 24. WPAG states that allocating hydro storage costs and internal hydro costs to the seasons based on storage withdrawals results in generation costs being allocated on the basis of hydro storage withdrawals. Id. WPAG claims that NIU has used energy withdrawn from storage to allocate storage costs and internal hydro costs, and then to allocate FBS generation costs as well. Id. WPAG concludes that if NIU had performed the analysis correctly, the method they used would yield the same results that BPA's method calculates. Id., 25.

WPAG is correct in asserting that the period of least thermal generation is the period of maximum storage buildup. Thus, it cannot be said that thermal resources are operated in the summer to increase hydro storage. This reasoning is consistent with BPA's reasoning in the 1985 rate case. 1985 Rates ROD, WP-85-A-02, 106. BPA's method for seasonally differentiating storage costs assumes that storage costs do not include generation costs. BPA's method entails the seasonalization of storage costs based on the withdrawal of energy from storage, and the seasonalization of generation costs based on seasonal energy generation of the FBS. It is inappropriate to seasonally differentiate all FBS costs on the basis of energy withdrawn from storage. This is what the NIU proposal suggests. For NIU's method to be consistent with BPA's approach to seasonalizing energy costs, only storage costs and imputed hydro costs of displacement would be seasonalized on the basis of energy withdrawn from storage. Total FBS costs less the storage and imputed hydro costs would be allocated to seasons based on total FBS energy generation. If this method were used, the results would be identical with BPA's method.

Decision

BPA will continue to seasonally differentiate all energy costs on the basis of historical monthly energy withdrawn from storage and the projected firm energy produced in each season, excluding May.

B. Section 7(b)(2) Industrial Adjustment

Issue

Should the applicable wholesale rate used in the calculation of the IP and VI plateau rate be based on the PF preference rate or some other form of the PF rate?

Evaluation of Positions

Section 7(c)(2) of the Northwest Power Act provides that rates applicable to the DSIs after July 1, 1985 "shall be based on the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates . . . ." 16 U.S.C. §839e(c)(2). The rate applicable to firm power sales to preference customers is the PF rate. In this rate proceeding, due to the triggering of the 7(b)(2) surcharge (see discussion in Chapter VI), the PF rate is bifurcated into the PF preference rate and the PF exchange rate.

After bifurcating the PF rate, and reducing the PF preference rate by the 7(b)(2) amount, BPA recalculates the DSI rate such that it is linked via the IP-PF Rate Link to the PF preference rate. Because the PF preference rate is lower than the average PF rate, the DSI rate is reduced. Any resulting revenue deficiency from the DSIs is calculated. This deficiency is allocated to all customer classes except the DSIs and the PF preference classes. This process is referred to as the 7(b)(2) industrial adjustment.

The IOUs claim that BPA proposes to provide the DSIs "price preference" through the 7(b)(2) industrial adjustment. Initial Brief, PP&L/PGE, B-PL/GE-01, 25. They argue that Congress intended the 7(b)(2) rate test to protect BPA's public body and cooperative customers, not the DSIs. Id., 26. They allege that the legislative history of the Northwest Power Act exclusively names only preference customers as beneficiaries of the 7(b)(2) rate test, and that the DSIs are never mentioned as beneficiaries. Id., 27. The IOUs also argue that the 7(b)(2) industrial adjustment contradicts Exhibit U to the 1981 BPA rate case. Id., 28. They claim that BPA has performed several calculations never mentioned in Exhibit U; specifically, the reduction of the DSI rates and the surcharge of the PF exchange rate. Brattebo/McCullough, IOU, E-IO-02, 4. The IOUs conclude that the DSI rate would be higher than BPA proposes if the specific language of Exhibit U is followed, alleging that the Administrator is contractually committed to follow Exhibit U for ratemaking purposes by General Contract Provision (GCP) section 8(e). Initial Brief, PP&L/PGE, B-PL/GE-01, 28.

PP&L argues that either the 7(b)(2) industrial adjustment is a 7(b)(2) surcharge, or it is not. Exceptions, PP&L, R-PL-01, 12. PP&L claims that if the industrial adjustment is a surcharge, it must be spread "through supplemental rate charges for all other power sold by the Administrator to all other customers." Id. Alternately, if the 7(b)(2) industrial adjustment is not a 7(b)(2) surcharge, it cannot be applied so as to increase the PF rate disparity between preference and nonpreference customers. Id.

WPAG argues that the sole purpose of the 7(b)(2) industrial adjustment is to extend the benefits of the preference customer rate test to the DSIs. McGary et al., WPAG, E-WA-03, 40-42; E-WA-03, 40-42. Therefore, states WPAG, the 7(b)(2) industrial adjustment is inappropriate and should be eliminated. Id. WPAG also argues that the rate test should not operate to provide lower rates to the DSIs than to preference customers. WPAG claims that the 7(b)(2) industrial adjustment has the pernicious effect of causing exchanging

preference customers to face a greater rate increase than the DSIs because they must pay a surcharge to provide rate test protection to the DSIs. Exceptions, WPAG, B-WA-02, 31.

PPC and WPAG also argue that if the rate test is extended to the DSIs, the cost of the industrial adjustment should not be allocated to exchanging preference customers, but only to nonpreference customers. Initial Brief, PPC/APAC, B-PA/PP-01, 9; Initial Brief, WPAG, B-WA-01, 36. PPC argues that the 7(b)(2) rate test is not intended to benefit nonpreference customers. Exceptions, PPC, R-PP-01, 23. PPC claims that it is reasonable for BPA to adopt an interpretation whereby the DSIs pay the applicable wholesale rate to preference customers that is unprotected by the rate test so as to avoid protecting the DSIs with the rate test, which is contrary to Congressional intent. Id.

The DSIs support BPA's position on the 7(b)(2) industrial adjustment. Initial Brief, DSI, B-DS-01, 20-22.

Section 7(c)(2) of the Northwest Power Act, 16 U.S.C. §839e(c)(2), provides that the DSI rate ". . . shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates . . . ." BPA's rate applicable to public body and cooperative customers is the PF preference rate. Armstrong/Revitch, BPA, E-BPA-22, 7; Schoenbeck, DSI, E-DS-03R, 3. Therefore, the DSI rate should be based on the PF preference rate as the applicable wholesale rate. This conclusion is also supported by the legislative history of the Northwest Power Act. Initial Brief, DSI, B-DS-01, 21. The 7(b)(2) industrial adjustment assures that the DSI rate is tied to BPA's PF preference rate. Armstrong/ Revitch, BPA, E-BPA-54, 6. However, the necessity of adjusting the applicable wholesale rate arises from the triggering of the 7(b)(2) rate test and it would be inappropriate to reduce the protection provided to the preference customers from the rate test by allocating a portion of the 7(b)(2) industrial adjustment to them. The 7(b)(2) adjustments, including the 7(b)(2) industrial adjustment are an internally consistent interpretation and implementation of the directives of sections 7(b)(2) and 7(c)(2) and require no judgment as to whether one provision should supersede the other.

The PPC/WPAG argument that the cost of the industrial adjustment should not be allocated to exchanging preference customers has no basis. The preference exchange loads are not protected by section 7(b)(2) and there is no statutory or other requirement that the rate paid by these customers should be limited to the PF preference rate.

The 7(b)(2) industrial adjustment is performed to address the requirements of section 7(c)(2) of the Northwest Power Act, 16 U.S.C.§839e(c)(2), as well as the requirements of section 7(b)(2). Because the PF rate is bifurcated as a result of the triggering of the 7(b)(2) rate test, it is necessary to continue to tie the DSI rate to the PF preference rate in accordance with section 7(c)(2). The allocation of the charges for the 7(b)(2) industrial adjustment follows the logic for allocating both the 7(b)(2) charges and the

7(c)(2) delta charges. That is, the charges are allocated to all non-PF preference customer classes and non-DSI customer classes.

The 7(b)(2) industrial adjustment does not contradict the post-1985 rate allocation process as described in Exhibit U. The IOUs themselves demonstrate that BPA has faithfully followed all the arithmetic steps indicated in Exhibit U. Brattebo/McCullough, IOU, E-IO-02, 4. BPA has, however, performed two additional steps in calculating the DSI rate on which Exhibit U is silent. These steps are the recalculation of the DSI rate based on the PF preference rate and the allocation of a resulting DSI revenue deficiency to other rate classes. Together these steps comprise the 7(b)(2) industrial adjustment. There is no consideration in Exhibit U, either express or implied, as to which PF rate should be the applicable wholesale rate on which to base the DSI rate in the event that the PF rate is bifurcated. The IOU arguments imply that because Exhibit U does not include a provision for linking the DSI rate to the PF preference rate, such a linkage is prohibited. The IOUs fail to recognize that this precise linkage is required in section 7(c)(2) of the Northwest Power Act. 16 U.S.C. §839e(c)(2).

Furthermore, Exhibit U does not contain a comprehensive description for establishment of DSI rates after July 1, 1985. For example, Exhibit U is silent on the floor rate test, which is also required by the Northwest Power Act. Initial Brief, DSI, B-DS-01, 22. Also, the BPA witness sponsoring Exhibit U in BPA's 1981 rate filing testified that Exhibit U reflected the analysis of rate directives performed in Appendix B for the post-85 years. Id. Appendix B based the DSI rate on the preference rate. Id.

Decision

The 7(b)(2) industrial adjustment is required by section 7(c)(2) of the Northwest Power Act. 16 U.S.C. §839e(c)(2). BPA links the DSI rate to the PF preference rate as the applicable wholesale power rate through the 7(b)(2) industrial adjustment. This adjustment is consistent with Exhibit U.

C. Rate Design Sequencing

Issue 1

Should BPA compute the equalization of demand adjustment based on the PF preference rate?

Evaluation of Positions

The IOUs argue that there is no rational basis for using a pre-7(b)(2) preference rate for calculating capacity rates and a post-7(b)(2) preference rate for calculating the DSI rate. Brattebo/McCullough, IOU, IO-02, 6. They propose that BPA should either eliminate the 7(b)(2) industrial adjustment, or compute the equalization of demand based on the post-7(b)(2) PF preference rate. Id.

WPAG opposes the IOU suggestion that the equalization of demand adjustment be sequenced after the 7(b)(2) adjustments. McGary et al., WPAG, E-WA-03, 41-42. WPAG agrees with the IOU position that the DSIs improperly benefit from the 7(b)(2) rate test. Id. However, they point out that granting the IOUs the benefit of the rate test inherent in sequencing the equalization of demand adjustment after the 7(b)(2) adjustment is hardly a solution to improperly allowing the DSIs to benefit from the 7(b)(2) rate test. Id.

The DSIs argue that there is no logical relationship between BPA's decision to base the DSI rate on a post-7(b)(2) preference rate and the equalization of demand calculation. Schoenbeck, DSI, E-DS-03R, 8. The DSIs allege that the 7(b)(2) adjustment and the equalization of demand must precede the determination of the DSI equitable rate because the wholesale rate applicable to public agencies for resale to industrial consumers incorporates both these steps. Id. The DSIs argue that BPA's determination to equalize demand is discretionary and should be performed in the sequence necessary to achieve BPA's policy objectives. Id., 8-9.

The IOUs draw a faulty analogy between the process used to calculate the DSI rate and the process used to calculate BPA's firm capacity rates. Section 7(c)(2) of the Northwest Power Act links the DSI rate to the PF preference rate (see Section B). No statutory requirement exists for linking BPA's CF rates to BPA's PF preference rate. To the contrary, section 7(e) of the Northwest Power Act allows considerable latitude in developing rate forms for the sale of peaking capacity. 16 U.S.C. §839e(e).

BPA's sequencing of the equalization of demand adjustment prior to the 7(b)(2) adjustments is reasonable. It does not provide the CF customers with the benefits of the 7(b)(2) rate adjustment by equalizing the rate to the PF preference demand charge. However, it also does not take what would appear to be the logical step of equalizing the CF rate with the PF exchange demand charge. Performing the equalization of demand adjustment prior to both the 7(c)(2) and the 7(b)(2) adjustments also avoids the recalculation of the DSI rate.

Decision

The sequencing of the equalization of demand adjustment prior to the 7(b)(2) adjustments is reasonable and avoids unnecessary complication of the rate development process.

Issue 2

Should the 7(b)(2) adjustments be performed before or after the DSI floor rate adjustment?

Evaluation of Positions

BPA proposes to perform the 7(b)(2) rate design adjustments prior to the DSI floor rate test in the rate development sequence. The 7(b)(2) adjustments include an adjustment which credits the 7(b)(2) amount to the PF preference

class and charges all other classes; the 7(b)(2) exchange cost adjustment; and the 7(b)(2) industrial adjustment.

The IOUs argue that section 7(b)(3) of the Northwest Power Act requires the Administrator to recover the amount of the 7(b)(2) subsidy through ". . . supplemental rate charges for all other power sold . . . ." Initial Brief, PP&L/PGE, B-PL/GE-01, 29-32. The IOUs claim that a supplemental rate charge is a charge that is added to a rate already charged. Id. They argue that the DSI rate is no higher with section 7(b)(2) triggering than it would have been if section 7(b)(2) had not triggered. Id. The IOUs state that the reason for this anomaly is that BPA allocates the 7(b)(2) surcharge to the DSI calculated rate, rather than to the floor rate actually charged. Id. Consequently, the DSIs' share of the 7(b)(2) surcharge is paid out of the floor rate benefits intended for the Administrator's other customers. Id.

The DSIs argue that BPA properly allocates the 7(b)(2) surcharge to the DSI equitable rate and then determines whether the DSI rate must be further increased to raise it to the floor. Schoenbeck, DSI, E-DS-01, 22-23. Thus, the DSI rate includes the full effect of the 7(b)(2) adjustments whether it is based on the equitable rate or the floor rate. Id. The DSIs also argue that Congress intended the floor rate to protect non-DSI customers from a decrease in the DSI rate level which could be caused by the change from the pre-1985 to post-1985 ratemaking directives. Id. The DSIs allege that the floor rate is a minimum level below which the DSI rate may not fall. Id.

BPA has stated two reasons for performing the DSI floor rate test subsequent to the 7(b)(2) adjustments. Armstrong/Revitch, BPA, E-BPA-54, 5-6. First, the 7(b)(2) amounts are allocated to the DSI calculated rate. Id. If the DSI rate is still below the floor rate after these allocations, BPA raises the DSI rate even further so that it is not below the floor rate. Id. Whether the DSI rate is the calculated rate or the floor rate, it includes the full effect of the 7(b)(2) allocations. Id. Second, if the floor rate test were performed prior to the 7(b)(2) adjustments, a second floor rate test would have to be performed because the 7(b)(2) industrial adjustment would reduce the DSI calculated rate. Id. It would be necessary at that point to determine whether the reduction to the DSI calculated rate caused by the 7(b)(2) industrial adjustment caused the DSI rate to fall below the floor. Id. The proposed sequencing of the floor rate test avoids the administrative inconvenience of having to repeat the floor rate test. Therefore, BPA sequences the floor rate test after the 7(b)(2) adjustments. Id.

In response to BPA's rationale, the IOUs claim that because the 7(b)(2) adjustments are made to the calculated rate and because the calculated rate is not the effective DSI rate, the 7(b)(2) adjustments to the DSI rate are meaningless. Brattebo/McCullough, IOU, E-IO-6SR, 1-2. The IOUs also argue that sequencing the floor rate test prior to the 7(b)(2) adjustments would not necessitate a repetition of the floor rate test. Id. Once the DSI rate is raised to the floor, the relationship between the DSI rate and the PF rate is broken. Id. Therefore, there is no need to perform the 7(b)(2) industrial adjustment, and hence no need to repeat the floor rate test. Id.

BPA is required to base the DSI rate "upon the Administrator's applicable wholesale rate to . . . public body and cooperative customers and the typical margins included by such . . . customers in their retail industrial rates . . . ." 16 U.S.C.§839(e)(c)(2). The calculated rate may be superseded by the legislative requirement that the DSI rate " . . . shall in no event be less than the rates in effect for the contract year ending June 30, 1985." 16 U.S.C §839e(c)(2)(C). The calculated DSI rate is the effective DSI rate unless it is below the level of the floor rate, in which case the calculated rate is always raised to the level of the floor rate. The DSIs will always pay either the calculated rate or a floor rate, whichever is higher.

Whether or not the DSIs would pay the same rate if the 7(b)(2) test triggers depends on the level of the calculated DSI rate in relation to the floor rate. The minimum rate that the DSIs pay is the floor rate. If the calculated DSI rate includes the 7(b)(2) allocations and is still below the floor rate, the DSI rate is increased further until it is equal to the floor rate. If, under BPA's proposal, the calculated DSI rate had been higher than the floor rate, the IOUs could not argue that the DSIs shoulder none of the burden of the 7(b)(2) surcharge. The fact that the DSI calculated rate is below the floor rate does not mean that the DSIs are not shouldering the 7(b)(2) surcharge, because such surcharge is allocated to them. Rather, it means that the level of the PF preference rate and the IP-PF Rate Link methodology result in a calculated DSI rate which is below the floor rate despite the fact that it was allocated the 7(b)(2) surcharges.

Decision

The DSI floor rate is the last step in BPA's rate development sequence, regardless of whether or not the 7(b)(2) rate test triggers. The DSI rate includes the 7(b)(2) surcharge.

D. DSI Floor Rate

In the 1985 Record of Decision, the methodology for determining the DSI floor rate was established for the first time. 1985 Rates ROD, WP-85-A-02, 177-191. It was decided that the DSI floor rate would be calculated according to the following methodology:

1. The IP-83 rate schedule would be applied to the test period DSI billing determinants.

2. The revenues resulting from applying the IP-83 rate schedule to the test period billing determinants would be adjusted for two items included in the IP-83 rate which were extraordinary, nonrecurring events: (a) the inclusion in the IP-83 rate of an amount for repayment of deferred interest expenses from prior years included in the OY 1985 test period revenue requirement, and (b) the fact that exchange cost estimates on which the IP-83 rate was based were estimates that assumed BPA's Average System Cost (ASC) methodology prior to October 1984 (initial ASC methodology) would be in place

during the OY 1985 test period. BPA implemented a new ASC methodology effective October 1984. The new ASC methodology resulted in significantly reduced exchange costs. Had the IP-83 rate been calculated with exchange cost estimates based on the new ASC methodology, that rate would have been lower. Consequently, BPA agreed in the 1985 rate proposal to adjust the DSI floor rate calculation accordingly.

3. The deferral adjustment in the 1985 rate case was expressed as a mills per kilowatthour quantity, and subtracted from the average rate calculated in Step 1. This quantity was calculated as the amount of deferral allocated to the DSIs in the IP-85 rate divided by test period OY 1985 DSI billing determinants.

4. The exchange cost adjustment in the 1985 rate case was calculated by applying the Exchange Adjustment Clause as prescribed in the 1983 General Rate Schedule Provisions to determine a hypothetical exchange cost rebate assuming the new ASC methodology had been in place for all of OY 1985. The hypothetical exchange cost rebate was, in the 1985 rate case, a quantity specified as a dollar amount reduction to the revenues resulting in Step 1 adjusted for Step 3.

5. The resulting adjusted revenues were then divided by test period (FY 1987) DSI billing determinants to determine an average rate expressed in mills per kilowatthour.

6. The adjusted DSI rate resulting from the foregoing steps was the DSI floor rate, prior to granting a Value of Reserves (VOR) credit.

Issue 1

Should the floor rate be set at a fixed average rate value established in the 1985 rate case, or should it be recalculated in this and in subsequent rate cases according to the formula approach adopted in the 1985 ROD?

Evaluation of Positions

The DSIs argue that once BPA determined a 22.8 mills per kilowatthour floor rate in the 1985 rate filing, the formula became irrelevant because the 22.8 mill per kilowatthour rate reasonably reflected "normalized" conditions for 1985 and prevented rate shock to other customers. Exceptions, DSI, R-DS-01A, Technical Appendix, 10. The DSIs argue that there is nothing inherently right about a rate formula unless it produces the correct rate. Id. The DSIs claim that for the floor rate, the right answer in 1985 was 22.8 mills per kilowatthour and 22.8 mills per kilowatthour remains the right answer today. Id.

In the 1985 ROD, the methodology for calculating a floor rate was expressed as a formula rather than being set at specific permanent level for all time. The reasoning stated in the 1985 ROD was that any floor rate test which uses loads that have been fixed in a single year is not logical because

of the permanence that would be embodied in the floor rate as a result of the aberrations inherent in that fixed set of loads. It was therefore more appropriate to assume that a floor rate test should be based on the application of the IP-83 rate schedule to a set of loads which normalize aberrations pertaining to seasonality, sales at the incentive rate, the effects of the customer charge on revenues, and other peculiarities indicated in arguments made by other customers. 1985 Rates ROD, WP-85-A-02, 182. Loads which have these aberrations removed are projected test period loads from the test year. Id. A further justification for adopting a formula, rather than a permanently fixed floor rate level, was that the formula approach allows BPA to change its rate design in subsequent rate filings and yet maintain an unbiased floor rate test. Id., 183.

The DSIs allege that BPA claims inconsistently that (1) the 22.8 mills per kilowatthour floor rate must be rejected because it does not comply with the formula and (2) the 1985 formula must be rejected because it was wrong all along. Exceptions, DSI, R-DS-01, 4. The DSIs are incorrect. BPA has not rejected the formula approach to calculating the floor rate. The DSIs themselves reject the formula approach by advocating that the results of the first application of the formula in the 1985 rate case should be permanently established as the floor rate in all future rate cases. BPA has faithfully adhered to the formula approach established in the 1985 ROD for calculating the floor rate. In so doing, BPA has updated information required by the formula and identified an error in the application of the formula prescribed in the 1985 ROD. The error related to the calculation of the exchange cost adjustment to the IP-83 rate itself (see Issue 5). If this error is not corrected, the formula approach will not be able to produce a correct, stable floor rate as originally intended. This error had only a minor effect on the level of the 1985 rates. Had BPA used the forecasted OY 1985 DSI loads from the 1983 rate case in the exchange cost adjustment to calculate the floor rate in the 1985 rate case, the floor rate would have been 22.9 mills per kilowatthour instead of 22.8 mills per kilowatthour. The major change in the level of the floor rate is due primarily to the use of actual OY 1985 ASC data in calculating the hypothetical exchange cost rebate amount. The DSI argument for fixing the floor rate in this rate case at the 1985 level and against using a formula approach appears to be more a rejection of the higher floor rate resulting from the correct application of the formula than a rejection of the formula itself.

Decision

The use of a formula is appropriate in calculating the floor rate. The formula that was established in the 1985 ROD, corrected for an implementation error in the calculation of the exchange cost adjustment, is hereby reaffirmed for the reasons stated in the 1985 ROD.

Issue 2

Should the DSI floor rate be based upon the IP-85 demand and energy charges applied to test period billing determinants?

Evaluation of Positions

The DSIs argue that the IP-85 charges constitute the floor rate. Schoenbeck, DSI, E-DS-01, 9; Schoenbeck, DSI, E-DS-05SR, 12; Initial Brief, DSI, B-DS-01, 5-8.

BPA testimony stated that the 1985 Administrator's Record of Decision established the floor rate calculation as the IP-83 charges applied to test period billing determinants, adjusted for inclusion of the deferral in the IP-83 rate, and further adjusted to eliminate the effects of implementation of BPA's new ASC methodology in test period OY 1985. Armstrong/Revitch, BPA, E-BPA-54, 4.

The DSI contention that the floor rate should be based on IP-85 charges applied to test period billing determinants is contrary to the Administrator's decision in the 1985 ROD. The DSIs assert that the 1985 ROD decided the level of the floor rate and, since the IP-85 rate was set at that level, the IP-85 rate is the floor rate. Initial Brief, DSI, B-DS-01, 5. However, the 1985 ROD actually determined that the floor rate was based on IP-83 rate charges applied to test period billing determinants, then adjusted for inclusion of the deferral and exchange costs under BPA's initial ASC methodology. 1985 Rates ROD, WP-85-A-02, 182-190. Moreover, the DSI argument assumes that demand and energy charges inherent in the IP-85 rate are identical to those in the IP-83 rate. The methodology stated in the 1985 ROD allowed for variations in load factor and relative usage patterns by applying the IP-83 rate charges (not the IP-85 charges) to test period billing determinants.

Decision

The DSI floor rate is based upon IP-83 rate charges applied to test period billing determinants, then adjusted for inclusion of deferral and exchange costs which assumed that BPA's initial ASC methodology would be in effect during OY 1985. This issue was decided in the 1985 ROD and is hereby reaffirmed.

Issue 3

Should the DSI floor rate be adjusted for the deferral and for exchange costs?

Evaluation of Positions

As noted above, in the 1985 rate case the Administrator determined that the floor rate was based on IP-83 rate charges applied to test period billing determinants, then adjusted for inclusion of the deferral and exchange costs under BPA's initial ASC methodology. 1985 Rates ROD, WP-85-A-02, 182-190. The IOUs oppose both the deferral and the exchange cost adjustments to the floor rate. Initial Brief, PP&L/PGE, B-PL/GE-01, 45-49; Initial Brief, Puget et al., B-PS/MP/WP-01, 22-23. Puget argues that the exchange cost and deferral adjustments to the floor rate are improper and violate BPA's statutory obligations as much in 1987 as they did in the 1985 rate proposal.

Exceptions, Puget et al., R-PS/MP/WP-01, 24. PP&L/PGE argue that the exchange adjustment did not affect the "rates in effect for the contract year ending June 30, 1985" because it did not operate retroactively. Initial Brief, PPL/PGE, B-PL/GE-01, 47. PP&L/PGE also claim that the exchange cost adjustment is unreasonable because BPA calculated the amount of the adjustment as if the new ASC methodology had been in effect on July 1, 1984, rather than October 1, 1984, when the new ASC methodology actually went into effect. Id. PPL/PGE argue that the deferral adjustment to the floor rate is improper because the deferral was a part of the "rates in effect" during OY 1985. Id., 48. Hence, they characterize both the deferral adjustment and the exchange cost adjustment as retroactive adjustments to the floor rate which cause the floor rate to be different from "rates in effect" during OY 1985. Id., 49.

WPAG agrees with the IOU position and argues that the instability in the floor rate can be eliminated by using the IP-83 rate and forecast DSI loads, without adjustments for the exchange and deferral. McGary et al., WPAG, E-WA-03, 29.

Neither the IOUs nor WPAG have raised new arguments regarding BPA's 1985 decision to adjust the floor rate calculation for the deferral and exchange cost adjustments. The arguments presented in testimony and briefs were made in the 1985 rate case and received a thorough and proper evaluation in the 1985 ROD. Armstrong/Revitch, BPA, E-BPA-54, 4-5. WPAG's argument regarding instability in the floor rate relates more to the implementation of the exchange cost adjustment than to the need for the adjustment and is addressed below in the context of the exchange cost adjustment issue.

Decision

The adjustments to the DSI floor rate for the deferral and exchange costs are appropriate. This issue was decided in the 1985 ROD and is hereby reaffirmed for the same reasons.

Issue 4

Should the exchange adjustment to the DSI floor rate use actual exchange cost data for OY 1985?

Evaluation of Positions

In the 1985 ROD, the DSI floor rate incorporated an exchange cost adjustment based on forecasted cost data for OY 1985. Actual cost data for OY 1985 were not then available; data now are available and were used in the initial and supplemental proposals to calculate the DSI floor rate. Armstrong/Revitch, BPA, E-BPA-54, 2.

The DSIs argue that Congress intended that the floor rate be based on forecasted data. Initial Brief, DSI, B-DS-01, 8-9. They cite section 7(c)(2) of the Northwest Power Act as requiring that the DSI rate beginning July 1, 1985, shall be based on the rates in effect for the year ending June 30, 1985. Id. The DSIs claim that "rates in effect" are always based on future

expectations, and that BPA does not subsequently "true-up" its rates by replacing all forecasted data with actual data. Id. The DSIs claim that the floor rate is no different. Id. They argue that the Administrator expressly found that the floor rate was a prospective rate that did not involve retroactive ratemaking. Id. This rate, once determined, should remain unchanged. Id. The DSIs claim that there can be only one floor rate. Id. The DSIs argue that "Staff's selective substitution of actual for forecasted data would be retroactive ratemaking and would cast doubt on the legality of past charges." Id.

WPAG argues that if BPA includes the exchange cost adjustment in the floor rate calculation, the adjustment should incorporate actual exchange cost data. Initial Brief, WPAG, B-WA-01, 38. WPAG alleges that there is no justification for doing otherwise. Id.

PPC supports BPA's decision to use updated exchange costs in its calculation of the DSI floor rate in this proceeding. Exceptions, PPC, R-PP-01, 25.

In the 1985 rate case, BPA adjusted the IP-83 rate for the inclusion of exchange costs which were forecasted under the assumption that the initial ASC methodology would be in effect during OY 1985. At that time, it was known that the new ASC methodology, which significantly reduced exchange costs, would be in effect for part of OY 1985. The OY 1985 test period was used in the 1983 rate proposal in which the IP-83 rate was developed. The Exchange Adjustment Clause was used to make this adjustment to the IP-83 rate for purposes of calculating the post-1985 DSI floor rate. The Exchange Adjustment Clause is a component of the IP-83 rate schedule and is described in the General Rate Schedule Provisions (GRSPs) to the 1983 Wholesale Power Rate Schedules.

The exchange cost adjustment to the IP-83 rate used to calculate the floor rate was intended to account for the difference in exchange costs arising from the extraordinary, nonrecurring, one-time phase in of BPA's new ASC methodology, as well as all other differences between forecasted and actual exchange costs resulting from forecasting error. 1985 Rates ROD, WP-85-A-02, 182-190. The Exchange Adjustment Clause was originally included in the 1983 rates to account for such differences between forecasted and actual exchange costs. Therefore, this was the logical and most convenient mechanism to use in the 1985 rate case to calculate a hypothetical exchange cost adjustment to the IP-83 rate which would eliminate the effects of the assumption that BPA's initial ASC methodology, rather than the new ASC methodology, would be in effect during OY 1985. BPA's intent was to calculate what the IP-83 rate would have been had the new ASC methodology been in place for the entire OY 1985 test year and had actual exchange costs been known. 1985 Rates ROD, WP-85-A-02, 188.

In the 1985 rate case, actual exchange cost data for OY 1985 were not known. BPA completed the 1985 rate proposal in May 1985, prior to the end of OY 1985, so actual exchange cost data for OY 1985 were not available at that time. In the calculation of the exchange cost adjustment to the floor rate, BPA used estimates of exchange costs in place of actual accounting data for

OY 1985. The floor rate calculation for the 1985 rate proposal was therefore based on estimates of exchange costs for OY 1985. In this rate case, all such historical accounting data are available and are used in the calculation of the exchange adjustment to the floor rate.

The DSI argument that BPA should not update the data used in the calculation of the exchange cost adjustment to the floor rate runs counter to the purpose of making the exchange cost adjustment. The DSI argument assumes that the calculation of the exchange adjustment in the 1985 rate proposal, which used estimates of OY 1985 exchange costs rather than historical accounting data, is a final calculation and cannot be changed, regardless of whatever inaccuracy it may contain. The DSI argument urges BPA to ignore the availability of accurate actual data and to allow the exchange cost adjustment to remain in a preliminary and inaccurate state simply because it results in a lower floor rate. BPA used the updated exchange cost data in this rate case because they are available and because they make the exchange cost adjustment to the floor rate accurate. Armstrong/Revitch, BPA, E-BPA-54, 2. Had these actual data been available in the 1985 rate proposal, they would have been used. It is appropriate to use the actual data in the exchange cost adjustment to the floor rate because by not doing so, the DSIs would be given undeserved benefits of estimated exchange costs being greater than actual exchange cost data. This logic is consistent with the reasoning offered by the DSIs when they urged BPA to make an exchange cost adjustment in the 1985 rate case. 1985 Rates ROD, WP-85-A-02, 188.

The DSIs argue that BPA's rates in effect are always based on future expectations, and that BPA does not subsequently "true-up" its rates by replacing all forecasted data with actual data. Initial Brief, DSI, B-DS-01, 7. They claim that the floor rate is no different. Id.

The logic for using the updated actual exchange costs for making the exchange cost adjustment to the floor rate is consistent with the fact that the Exchange Adjustment Clause is part of the IP-83 rate and would have modified the IP-83 rate to reflect actual exchange costs. BPA does not engage in retroactive ratemaking. However, when an adjustment clause is included in a rate schedule, it not only allows, but requires a "truing-up" of rates for a specific cost item. Performing a rate adjustment required by an adjustment clause would never cast doubt on the legality of past charges so long as the adjustment is performed correctly. The DSI argument urges BPA to perform the exchange cost adjustment incorrectly.

Decision

It is appropriate to use actual exchange cost data in the calculation of the DSI floor rate exchange cost adjustment.

Issue 5

What are the appropriate DSI loads to use in calculating the exchange cost adjustment to the DSI floor rate?

Evaluation of Positions

The 1985 floor rate methodology described at the beginning of this section was applied in BPA's initial and supplemental proposals in this rate case. Between those proposals, there was an unexpected reduction in the floor rate caused by an increase in the exchange cost adjustment. A review of the method used to adjust the IP-83 rate for the difference between exchange costs under the old and new ASC methodologies indicated that BPA's methodology from the 1985 rate proposal for making such an adjustment was in error. The methodology described above erroneously divided the exchange cost adjustment amount by test period billing determinants. Armstrong/Revitch, BPA, E-BPA-54, 2. The effect of this error was that the exchange cost adjustment was not fixed in relation to the IP-83 rate and could vary dramatically from one rate case to the next with changes in DSI load forecasts. Dividing the exchange cost adjustment amount by forecasted test period DSI billing determinants is incorrect because such an implementation of the exchange cost adjustment does not adjust the IP-83 rate to exclude the effects of implementing the new ASC methodology. BPA's methodology merely adjusted floor rate revenues by a fixed amount, whereas the IP-83 rate itself had to be adjusted. Moreover, BPA's method for implementing the exchange cost adjustment was not consistent with the implementation of the deferral adjustment. In rebuttal testimony, BPA proposed to correct this error by use of DSI billing determinants forecast for OY 1985 in the 1983 rate case as the denominator in the calculation of a mills per kilowatthour exchange cost adjustment consistent with the deferral adjustment. Id., 3.

The DSIs assert that the correction of this error represents a rejection by BPA of the 1985 floor rate formula. Exceptions, DSI, R-DS-01, 5. This is incorrect. The Administrator's decision in the 1985 ROD outlines the basic design and the intent of the floor rate calculation. It did not delineate the specific formula to be used to calculate the two adjustments. What BPA has corrected is an error in the specific implementation of that decision that would lead to an unstable floor rate, to the extent that DSI load forecasts vary from one rate case to the next. This is neither a rejection nor a repudiation of that 1985 ROD decision. The DSIs do not disagree that there is an error in the implementation of the 1985 ROD decision. In fact, the DSIs propose three alternative determinations of the floor rate. However, two of these alternatives, the use of the IP-85 rate and the use of the 22.8 mill per kilowatthour floor rate from the 1985 rate case results, are clearly inconsistent with the decision in the 1985 ROD as discussed above. The third DSI alternative floor rate method, the backcasting of OY 1985 loads with the Aluminum Smelter Model as a proxy for actual OY 1985 loads is also inconsistent with the methodology outlined in the 1985 ROD.

The DSIs argue that BPA's proposed method for making the exchange cost adjustment to the floor rate is incorrect because it mixes actual data with forecasted data. Schoenbeck, DSI, E-DS-05SR, 7. The DSIs claim that use of actual costs with forecasted DSI loads to make the exchange cost adjustment is internally inconsistent, theoretically unsupportable, and produces a much higher floor rate than would be produced through the consistent use of either actual or projected data. Id. They propose that if BPA is going to use

actual exchange cost data, then BPA should also use simulated actual DSI load data. Id.

The DSIs are incorrect that actual OY 1985 loads would be the most appropriate loads to use in the exchange cost adjustment. As noted by the DSIs, actual loads were rejected for the floor rate determination in the 1985 rate case because of the incentive rate offers in 1985. More importantly, the use of actual OY 1985 loads would be inconsistent with the intent of the floor rate determination.

The Administrator concluded in the 1985 ROD that the floor rate should be based on the IP-83 rate schedule applied to test period DSI billing determinants. Further, the IP-83 rate was to be adjusted for the extraordinary and nonrecurring exchange and deferral costs included in the IP-83 standard rate. 1985 Rates ROD, WP-85-A-02, 188. The intent was that by using test period billing determinants for application of the IP-83 standard rate, the anomalies present in the OY 1985 actual loads could be avoided. Id., 182. These anomalies included the incentive rate offers, the seasonality of the loads outside the incentive rate offers, and the potential for the DSIs to have manipulated their loads to set a lower floor rate. Id.

However, as noted earlier, the use of test year billing determinants in the two adjustments to the IP-83 standard rate would have made the adjustments, and consequently the floor rate, unstable. In addition, the intent of the adjustment was to adjust the IP-83 rate, not the floor rate revenues in the test period, for extraordinary and nonrecurring events. Id., 188. These adjustments were intended to be straightforward calculations that merely adjusted costs included in the IP-83 rate. Id., 189. It was not intended that they also adjust the IP-83 rate for differences between forecasted and actual DSI loads. In keeping with that intent, the deferral adjustment was made with forecasted OY 1985 loads from the 1983 rate proposal in the denominator. WP-85-FS-BPA-08A, 15. The result is essentially what the IP-83 rate would have been had the deferral not been included as a cost in the development of the IP-83 rate. There is no basis for concluding that the intent for the exchange cost adjustment is any different; i.e., to calculate what the IP-83 rate would have been had BPA forecasted OY 1985 exchange costs at the level that those costs were actually incurred in OY 1985. Consistent with the 1985 ROD, it is appropriate to apply the adjusted IP-83 rate to test period billing determinants in calculating the floor rate. It is inappropriate to adjust the IP-83 rate itself by use of either test period loads or actual loads in the denominator of the adjustment. The correct loads to use in adjusting the IP-83 rate are the loads that were used in the original calculation of that rate. Those loads are the forecasted loads for OY 1985 that were originally used in the 1983 rate filing when the IP-83 rate was developed.

The DSIs argue that because the methodology in the IP-83 Exchange Adjustment Clause was used in the calculation of the mills per kilowatthour exchange cost adjustment to the IP-83 rate, it is incorrect to mix actual data in the numerator (the hypothetical exchange cost rebate due the DSIs for OY 1985) with forecasted data (forecasted OY 1985 DSI billing determinants from the 1983 rate case) in the denominator. Schoenbeck, DSI, E-DS-05SR, 7.

The DSIs have suggested that BPA should "backcast" actual DSI loads using the Aluminum Smelter Model with actual aluminum prices for OY 1985 as input, with the assumption that they purchased power at the IP-83 rate, and that these are the correct loads to use in the denominator of the exchange adjustment to the IP-83 rate. Id. This argument is not persuasive. The Exchange Adjustment Clause provided a convenient and effective methodology for calculating the difference between forecasted and actual exchange costs under the different ASC methodologies. This mechanism does not require an examination of actual loads of any customer class. In fact, the Exchange Adjustment Clause mechanism calculates an exchange cost rebate (or surcharge) independently of differences between forecasted and actual DSI loads. To use actual loads in the denominator of the exchange cost adjustment to the IP-83 rate would be inconsistent with the intent of the adjustment as a modification to the IP-83 rate for exchange costs only, and could produce an absurd result.

As an example, assume the DSIs placed a load of only one kilowatthour on BPA during OY 1985, and received a $50 million exchange cost rebate. The effective rate to the DSIs would be a negative $50 million per kilowatthour. However, the "rate in effect" during the period was the IP-83 rate. If this example had actually happened, under the floor rate methodology for the exchange cost adjustment proposed by the DSIs, the floor rate resulting in this rate proposal would be in the neighborhood of a negative $50 million per kilowatthour. Clearly, this is not consistent with the intent of making the exchange cost adjustment to the IP-83 rate.

BPA recognized that the exchange cost adjustment to the IP-83 rate had been incorrectly performed in the 1985 rate case and in the initial and supplemental proposals in this rate case. Armstrong/Revitch, BPA, E-BPA-54, 3. BPA proposed to correct this error by dividing the exchange cost adjustment amount by DSI billing determinants forecasted for OY 1985 in the 1983 rate case. These are the same loads that were used to develop the IP-83 rate and use of these loads in the denominator of this adjustment correctly adjusts the rate. Moreover, performing this adjustment as BPA proposes makes it consistent with the calculation of the deferral adjustment which uses the same loads in the denominator.

Decision

The exchange adjustment to the floor rate is the exchange cost adjustment amount divided by DSI billing determinants forecasted for OY 1985 in the 1983 rate case. This insures that the IP-83 rate is properly adjusted for the implementation of BPA's new ASC methodology during OY 1985. It also insures that the implementation of the adjustment is consistent with implementation of the deferral adjustment.

Issue 6

Does the BPA methodology for calculating the level of the floor rate result in a stable floor rate over time?

Evaluation of Positions

BPA proposes to update the exchange cost adjustment to the floor rate with actual exchange costs for OY 1985. These historical accounting costs will not change in future calculations of the DSI floor rate. BPA has also identified an error in the adjustment of the IP-83 rate for the exchange cost adjustment, and has proposed to correct it by calculating a mills per kilowatthour adjustment using the same billing determinants in the denominator that were used in developing the IP-83 rate. Armstrong/Revitch, BPA, E-BPA-54, 3. The update of estimates to actual exchange costs and the error cited above were the only causes of instability in the floor rate. BPA expects no further changes in either the data or the methodology used to adjust the floor rate for the exchange cost adjustment. Id.

WPAG indicates that the reason the DSI floor rate can move over time is due to the exchange adjustment and its treatment as a dollar adjustment rather than a mills per kilowatthour adjustment McGary et al., WPAG, E-WA-03, 28. BPA's proposal eliminates the dollar adjustment and performs the adjustment as a mills per kilowatthour adjustment. WPAG also states that BPA's proposed method is a significant improvement over the previous method and comports with the Administrator's decision to include such an (exchange cost) adjustment. McGary et al., WPAG, E-WA-04, 36. WPAG also states that the method of fixing the exchange adjustment using actual exchange costs and projected DSI loads from the 1983 rate proposal provides predictability and stability, while at the same time remaining consistent with the original purpose of the adjustment. Id., 36. WPAG correctly describes BPA's proposal "to calculate the adjustment one time only and use that value each time the Floor Rate is recalculated." Id. WPAG concludes that BPA's method for calculating the exchange cost adjustment will eliminate the instability associated with using forecasted test period DSI loads. Id.

The DSIs claim that the IP/PF Rate Link cannot provide stability or predictability if the floor rate is neither stable nor predictable. Initial Brief, DSI, B-DS-01, 8. They argue that if the floor rate is allowed to change in this proceeding, there is no basis for concluding that BPA will not change its mind in future rate cases to produce new floor rates. Schoenbeck, DSI, E-DS-05SR, 13. They claim that it is unreasonable to conclude that BPA's new floor rate is more stable that the Administrator's old floor rate. Id.

Since the 1985 rate case, the DSI rate has been made more stable and more predictable by a number of factors. The IP-PF Rate Link adds an element of predictability to the DSI rate by linking it to the PF rate. The Variable Industrial rate provides stability to aluminum smelters by linking the price of electricity to the price of aluminum. This rate case has greatly increased the predictabilities of the DSI rate by resolving a number of previously unresolved issues. These issues include implementation of section 7(b)(3) of the Northwest Power Act, the effect of the triggering of the 7(b)(2) test on the applicable wholesale rate, the sequencing of the 7(b)(2) allocation and floor rate, and the application of the CRAC to the margin-based rate. The correct implementation of these rate design features is essential to the stability they provide. The correct implementation of the floor rate

methodology as intended in the 1985 Rates ROD is also essential to providing rate stability and rate predictability to the DSIs.

The DSIs' apprehensions about the stability of the floor rate are unfounded. BPA's proposal calculates the floor rate accurately with actual exchange costs that will not change, and by a correct methodology that does not allow the floor rate to vary with forecasts of the level of DSI loads in future rate filings, as was the case in BPA's initial and supplemental rate proposals. BPA's proposal is as stable as the DSIs' proposal to use the IP-85 rate as the floor rate, but BPA's proposal provides for a correct calculation of the floor rate. BPA's proposal is also as stable as the IOU proposal to use the IP-83 rate without adjustments. The only variance in the floor rate in future rate proposals would result from changes in DSI load characteristics, as was intended in the 1985 ROD decision, by use of the IP-83 rate applied to test period billing determinants. The IP/PF Rate Link does not apply when the effective DSI rate is the floor rate. However, the stability inherent in BPA's proposed floor rate calculation will add to the DSI rate stability already provided through the IP/PF Rate Link.

Decision

BPA's proposed method for calculating the exchange cost adjustment will result in a stable floor rate. BPA is committed to using that method in future rate cases.

E. WNP-1 Exchange

Issue

Should BPA assume that payments for power made available to investor-owned utility participants in the WNP-1 exchange agreements will be made at the PF preference rate or the PF exchange rate?

Evaluation of Positions

The IOUs claim that participants in the WNP-1 exchange agreements are entitled to choose the rate schedule applicable to their payments for power and energy made available by the Administrator under the agreements. Brattebo/McCullough, IOU, E-IO-02, 2. The IOUs suggest that BPA should assume that WNP-1 participants will exercise their rights and choose to receive power under the PF preference rate. Id. The IOUs argue that it is not appropriate to assume a surcharge to a class of customers if those customers can avoid such a surcharge by their choice of rate schedule. Id. This position is also advocated by Puget, WWP, and MPC. Initial Brief, Puget et al., B-PS/MP/WP-01, 22; Initial Brief, WUTC, B-WU-01, 8-9. WUTC alleges that it is inappropriate to apply the 7(b)(3) surcharge to an exchange of power. Id.

Conversely, PPC and APAC argue that the IOU position is inconsistent with the language of the WNP-1 agreements. Initial Brief, PPC/APAC, B-PA/PP-01, 10-12; Exceptions, PPC, R-PP-01, 24. PPC and APAC claim that utilities

participating in the WNP-1 exchange should pay, at a minimum, the PF exchange rate. Id.

Section 6 of the WNP-1 exchange agreements (BPA Contract Nos. 14-03-39212 through 39216) addresses payment by participating utilities for power deliveries by the Administrator. Section 6(a) provides that "at least 90 days in advance of the initial Contract Year, the Company shall designate by written notice to Supply System and the Administrator, from among the Administrator's Wholesale Rate Schedules (Schedules) which would then be applicable to similar direct sales of firm electric power and energy by the Administrator, the rate schedule(s) to be applied in determining payments under this section 6(a)."

The contractual language does not provide participating utilities with an indiscriminate right to designate the rate schedule applicable to the WNP-1 exchange. Such rate schedules must be "applicable to similar direct sales of firm electric power and energy by the Administrator." This language, however, is ambiguous. BPA and participants in the WNP-1 exchange agreements have previously interpreted this language to allow participating utilities to purchase power at the PF rate. Brattebo/McCullough, IOU, E-IO-02, 2. Furthermore, firm power sales at the PF preference rate constitute "similar direct sales of firm electric power and energy by the Administrator." Simply because only preference requirements customers purchase at the PF preference rate does not change the fact that such sales are similar as direct sales of firm electric power and energy. The intent of the parties to the WNP-1 exchange agreements was to allow participating utilities to designate from among the Administrator's rate schedules for firm power sales. The PF preference rate is one such rate schedule.

PPC/APAC argue that section 7(b)(2) of the Northwest Power Act applies solely to "the combined general requirements of public body, cooperative and Federal agency customers." Therefore, PPC/APAC claim that a determination that the PF preference rate is available to utilities participating in the WNP-1 exchange agreements would be contrary to section 7(b)(2). Initial Brief, PPC/APAC, B-PA/PP-01, 11. This argument, however, is unconvincing. First, the fact that section 7(b)(2) applies solely to preference customers does not preclude parties from designating a particular rate schedule as applying to power sales in a different contract. Second, section 7(b)(3) of the Northwest Power Act provides that amounts not charged to preference customers under section 7(b)(2) "shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." This language gives the Administrator discretion to allocate the amount of the surcharge among individual sales of "all other power." There is no requirement, as found later in section 7(b)(3), that such allocations be applied proportionately. 16 U.S.C. §839e(b)(3).

Finally, the manner in which purchases at the PF preference rate for WNP-1 exchange purchases are reflected in the rate development process ensures that the protection provided to preference customers by section 7(b)(2) is not reduced. Had the section 7(b)(2) rate test not triggered, purchases under the WNP-1 exchange agreements would have been made at the PF rate without dispute with the section 7(b)(2) rate test triggering. The amount of the 7(b)(2)

adjustment accruing to the preference customers is the same whether these purchases are made at the PF preference rate or the PF exchange rate as a result of increasing the 7(b)(2) adjustment amount by the 7(b)(2) trigger multiplied by the preference customer loads and the WNP-1 exchange loads. Therefore, the revenue difference between charging the WNP-1 exchange utilities the average PF rate and PF preference rate is not borne in any way by the preference customers, but is allocated to other customers.

Decision

Consistent with the terms of the contracts, payments by investor-owned utilities for power made available under the WNP-1 exchange agreements will be assumed to be made at the PF preference rate.

F. Section 7(b)(3)

Issue

Is a rate adjustment needed under section 7(b)(3) of the Northwest Power Act as a result of a net revenue surplus or deficiency for the period ending June 30, 1985?

Evaluation of Positions

Section 7(b)(3) of the Northwest Power Act, in pertinent part, states:

> Rates charged public body, cooperative, or Federal agency customers pursuant to this subsection shall not include any costs or benefits of a net revenue surplus or deficiency occurring for the period ending June 30, 1985, to the extent such surplus or deficiency is caused by --
>
> (a) a difference between actual power deliveries and power deliveries projected for the purpose of establishing rates to direct service industrial customers under subsection (c)(1) of this subsection, and (b) an overrecovery or underrecovery of the net costs incurred by the Administrator under section 5(c) as a result of such difference. 16 U.S.C. §839e.

Section 7(b)(3) also provides for the recovery or repayment of any such revenue surplus or deficiency after July 1, 1985. Section 5(c) provides for the residential exchange.

For the 7(b)(3) period ending June 30, 1985, there was a net revenue surplus of $38.65 million dollars. Melton/Leonard, BPA, E-BPA-21, 1; E-BPA-06, A7-8. This net revenue surplus exists even though there was a difference between the actual power deliveries and the projected power deliveries to the DSIs. A net revenue surplus cannot result from a revenue underrun. Melton/Leonard, BPA, E-BPA-56, 2. Because BPA recovered all of its costs including those of the residential exchange for the period ending June 30, 1985, the extent to which the DSI underrun contributed to a net

revenue deficiency is zero. Id. Simply put, the requirement of section 7(b)(3) that a net revenue deficiency exist for the period in order to surcharge nonpreference customers is not met.

APAC and PPC argue that the allocation of the deferral in the 1982 and 1983 rate cases to all customers caused the preference customers to pay a portion of the DSI obligation for exchange costs, and that preference customers should not pay for any failure of BPA to recover the net residential exchange costs from the DSIs. Initial Brief, APAC/PPC, B-PA/PP-01, 13; Initial Brief, APAC, B-PA-01, 5. They assert that an underrecovery alone may be sufficient to trigger a 7(b)(3) surcharge. Initial Brief, APAC/PPC, B-PA/PP-01, 15. APAC and PPC claim that BPA erred in its calculation of the net revenue surplus. Id. In comparing the difference between planned and actual funds from operations, BPA adjusted planned funds by deducting a deferral amount, and compared this to actual funds from operations which were collected as a result of including the deferral. Id., 16. They claim this is internally inconsistent and grossly unfair to the preference customers. Id. They assert that BPA may not now use the deferral as a mechanism to avoid the 7(b)(3) surcharge. Id., 17; Reply Brief, APAC/PPC, R-PA/PP-01, 10-11. APAC and PPC assert the proper calculation yields a surcharge to the DSIs of $31 million. Id., 18; Initial Brief, APAC, B-PA-01, 6; Exceptions, APAC/PPC, R-PA/PP-01, 12.

APAC and PPC assert that BPA did not follow the language of section 7(b)(3) in BPA's methodology of calculating whether there was a net revenue surplus or deficiency. As shown at the beginning of this discussion, the express language of the statute requires a determination of whether there was a net revenue surplus or deficiency for the period ending June 30, 1985, which was caused by an undercollection or an overcollection of net costs for the residential exchange as a result of a difference between actual and projected loads of the DSIs. Section 7(b)(3) addresses itself to the entire period ending June 30, 1985, and addresses BPA's net revenues.

The parties agree that for the period ending June 30, 1985, BPA recovered a net revenue surplus of some $38.65 million. BPA did not have a net revenue deficiency. Wolverton/Drummond, APAC/PPC, E-PA/PP-01, 13; BPA, E-BPA-06, A7; Schoenbeck, DSI, E-DS-03R, 11, 15-16; Initial Brief, PL/GE, B-PL/GE-01, 34-35; Exceptions, DSI, R-DS-01, 8. A net revenue surplus does not result from an undercollection of costs for the period. Melton/Leonard, BPA, E-BPA-56, 2. BPA has collected all of its exchange costs for the period as the DSIs noted; no evidence was presented by APAC or PPC that the net revenue surplus resulted from any undercollection of revenues from the DSIs. Initial Brief, DSI, B-DS-01, 24.

The deferral amount was an amount properly collected by BPA from all of its customers in order for BPA to meet its Treasury obligations. BPA's Treasury obligations are part of its revenue requirement just as are its other obligations. APAC and PPC argue that the deferral amounts should be ignored in calculating BPA's net revenue surplus for the period. Actually, what APAC and PPC ask is that BPA construct a hypothetical scenario for what revenues and costs would have looked like for the period absent any amounts collected for the deferral. They assert that BPA should hold "all else equal" and

assume that the deferral amounts were not collected or rates were lower and that BPA had a net revenue loss. Wolverton/Drummond, APAC/PPC, E-PA/PP-01, 16; Exceptions, APAC, R-PA-01, 10.

Section 7(b)(3) does not require BPA to speculate regarding revenue effects of lower rates or to assume that all else is equal. The deferral was an appropriate cost and was appropriately charged during the period to meet BPA payment obligations. The DSIs claim APAC and PPC attribute all of the deviation between the planned funds and actual results to the revenues collected from the DSIs and the net exchange costs. Initial Brief, DSI, B-DS-01, 25. The DSIs argue that the APAC/PPC approach ignores several other significant factors which may have affected costs in the period absent the deferral. Id. For example, both costs and revenues would have to be analyzed. Although revenues were less than anticipated, costs also were less than estimated. Leonard, BPA, TR 2168-69, 2176; BPA, E-BPA-06A, 566-67. The argument of APAC and PPC that preference customers prepaid costs of the exchange through their payment of deferral amounts is flawed because it fails to account for all the variable factors including cost reductions and preference customer underruns over the period. Moreover, the APAC/PPC assertion that preference customers are owed $31 million must be balanced against the fact that revenue from preference customers also underran projections.

APAC and PPC argue that BPA erred in calculating the net revenue surplus for the period which included the deferral amount because BPA adjusted the planned funds by deducting an amount for the deferral, but then compared this amount to actual funds from operations which included the deferral amounts collected. Initial Brief, APAC/PPC, B-PA/PP-01, 16; Exceptions, APAC/PPC, R-PA/PP-01, 11-12. APAC and PPC are incorrect. The calculation of net revenue surplus did not exclude the amount of the deferral from the planned funds from operations for the period. BPA, E-BPA-06, A3, A8. BPA adjusted the amount of the deferral so that the actual amount of the deferral at the beginning of the period would be included. Id. If this adjustment was not made the planned funds from operations for the 7(b)(3) period would be overstated. Interest expense incurred during the period would be counted more than once, first as interest and again each time it was deferred during the period. This adjustment eliminates the multiple counting and provides a correct measure of the planned funds from operations for the entire 7(b)(3) period. Leonard, BPA, TR 2169-2172. Both the planned funds from operations and the actual funds from operations included amounts for the deferral. Thus, there was no inconsistency; the methodology was not unfair. Moreover, the statute directs BPA to calculate its net revenue surplus or deficiency for the period and this is what BPA has done. 16 U.S.C. §839e(b)(3). In addition, APAC's and PPC's argument that BPA erred in calcating the net revenue surplus is inconsistent with their testimony that the $38.65 million net revenue surplus was a reasonable result. Wolverton/Drummond, APAC/PPC, E-PA/PP-01, 13.

APAC and PPC also argue that the Administrator committed BPA to calculating the section 7(b)(3) amount in a manner that would protect preference customers from an underrecovery of the net cost of the residential exchange from the DSIs even with the deferral. Initial Brief, APAC/PPC, B-PA/PP-01, 17; Exceptions, APAC/PPC, R-PA/PP-01, 11-12. They argue that in

prior rate cases they raised the issue of allocating the deferral on a cost causation basis rather than on a uniform basis to all loads; and that BPA cannot now use the deferral to avoid allocation of a surcharge to the DSIs. Initial Brief, APAC/PPC, B-PA/PP-01, 16-17; Exceptions, APAC/PPC, R-PA/PP-01, 12.

However, as the DSIs point out, the Administrator has found that the deferral was caused not by any single customer group, specifically the DSIs, but by all customer classes of BPA. Initial Brief, DSI, B-DS-01, 25, citing 1983 Rates ROD, WP-83-A-02, 171; 1982 Rates ROD, 58. For example, the revenues from nonexchanging preference customers' power sales were less than the costs allocated to them during the 7(b)(3) period. Id. 25-26; Melton/Leonard, BPA, E-BPA-56, Attachment 1. The 1983 ROD pointed out that identification of any past underrecovery of costs from the DSIs would necessitate a full comparison of all actual and forecast data used in setting previous rates. No party in those cases proposed a methodology to do this and APAC and PPC have not done so here. APAC and PPC have simply treated the underrecovery of net exchange costs from the DSIs as though it was all included in the deferral. Because the deferral was the result of all transactions, including those with public agency customers as well as DSIs, it was appropriate to allocate the deferral over all BPA loads. The uniform allocation was reasonable.

The DSIs argue that section 7(b)(3) specifies certain events which must cause a BPA net revenue surplus or deficiency for the period in order for there to be a surcharge or a refund, and no refund or surcharge is required. Initial Brief, DSI, B-DS-01, 23-24. They argue that no party contests that BPA enjoyed a net revenue surplus. Id., 24. They assert that BPA recovered all of its exchange costs in the period and that no evidence was presented which demonstrated that the net revenue surplus was caused by an overrecovery or underrecovery of the net costs of the exchange by BPA receiving less revenue from the DSIs than originally projected. Id. No refund or surcharge is required because the surplus was not caused by a statutorily specified event. Id; Reply Brief, DSI, DS-01, 8.

The DSIs further argue that the need for the deferral included in the rates was not caused by any one customer group, but by all. Id., 25. APAC/PPC's calculation incorrectly assumes that the total deviation between projected and actual results for the period related wholly to revenues collected from the DSIs and the net cost of the exchange. Id. This assumption ignores other significant differences between projected and actual results, including the preference customer revenue underrun of $161.8 million for the period October 1, 1982, through June 30, 1985. Melton/Leonard, BPA, E-BPA-56, Attachment 1. The $81 million of deferral allocated to preference customers was only 54 percent of the amount of their revenue underrun. Initial Brief, DSI, B-DS-01, 25-26, citing Schoenbeck, DSI, E-DS-03R, 14 and Wolverton/Drummond, APAC/PPC, E-PA/PP-01, Attachment F, 1.

PP&L and PGE argue that the statute provides that preference customers shall not be charged for a net revenue deficiency for the period which is caused by an underrecovery of residential exchange costs. Initial Brief, PL/GE, B-PL/GE-01, 34-35. They posit that section 7(b)(3) protection is

effective only if each of three conditions is met: first, DSI loads were different than those projected by BPA; second, that this difference resulted in an underrecovery of net exchange costs, and third, an overall net revenue deficiency for the period exists. Id. Because BPA correctly determined that there was a net revenue surplus and not a deficiency, no surcharge need be allocated. Id.

In Atlantic Richfield Co. et al. v. BPA et al., No. 83-7971; No. 83-7981; No. 7473; No. 85-7488, slip op. (9th Cir. June 5, 1987), the DSIs challenged BPA's customer charge in their BPA contracts. Since the charge was part of BPA's revenues during the period, BPA has stated it would reexamine its net revenues for the period were the DSIs allowed any recovery by the Court. Melton/Leonard, BPA, E-BPA-56, 3. This is unlikely since the Court has ruled BPA's customer charge is lawful.

Decision

Section 7(b)(3) requires BPA to determine whether there was a net revenue surplus or deficiency for the period ending June 30, 1985. No party disputes that BPA had a net revenue surplus for this period. Although BPA found that there also had been an underrecovery from the DSIs, BPA in fact recovered all of its costs for the period, including the costs of the exchange, and more. The net revenue surplus for the period was not caused by an underrecovery of net exchange costs as a result of an underrun of DSI loads. Consequently, one of the required elements for a surcharge is not present and an adjustment is not necessary.

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CHAPTER VIII

RATES FOR NONFIRM ENERGY

A. Introduction

In the nonfirm energy market BPA faces competition from numerous PNW and PSW utilities and from alternative fuel sources, specifically gas and oil. Buyers of nonfirm energy have the choice of operating their own generation, primarily gas- and oil-fired generation, or purchasing nonfirm or other economy energy. Prices for gas and oil used in electric generation changed dramatically in the spring of 1986. The rapid decline in prices during this period and the rapid reaction of regulators to reflect these lower prices in utility generation costs led BPA to adopt a more flexible, more competitive rate for sales of nonfirm energy (the NF-85 modified rate). The designs of BPA's rates for nonfirm energy sales seek to accommodate the competitiveness of these markets and future gas and oil price uncertainty.

The Nonfirm Energy (NF-87) rate is BPA's primary rate for marketing nonfirm energy. The NF-87 rate is based on BPA's average cost of nonfirm energy. An experimental Share-the-Savings (SS-87) rate, based on the value of nonfirm energy to the purchaser, also is available.

BPA's nonfirm energy rate package also includes a proposed 12-year NF rate cap applicable to all future nonfirm energy transactions irrespective of rate design (i.e., a cost-based or value-based rate). The NF rate cap is a function of both BPA's cost and PSW decremental fuel costs.

B. NF-87 Rate

1. Nonfirm Energy Cost Determination and Recovery

Issue 1

Are conservation costs, fish and wildlife costs, FCRTS costs, exchange resource costs, and the costs of WNP-1 and -3 properly included in the NF-87 average cost of nonfirm energy?

Evaluation of Positions

BPA's initial proposal set the average cost of nonfirm energy equal to the average cost of service from all of BPA's system resources including conservation resources, plus other operational costs and the FCRTS costs associated with that portion of the transmission system used to deliver bulk power from the source of generation to the service areas. BPA, E-BPA-06, 78.

NWP supports BPA's initial determination of the average cost of nonfirm energy and agrees that residential exchange resource costs are properly

included in the cost determination. Peters/Opatrny, NWP, E-NP-01, 3; NWP, WP-87-M-100, 4. APAC and PPC join NWP in opposing removal of exchange costs from the nonfirm energy rate. Exceptions, APAC, R-PA-01, 9; Exceptions, PPC, R-PP-01, 25. WPAG concurs. Exceptions, WPAG, B-WA-02, 26.

California parties and participants argue that BPA has included virtually all of its costs in determining the cost of nonfirm energy. Specifically, CEC objects to including costs they argue are unrelated to the production of nonfirm energy. The nonproduction-related costs identified by the CEC include Supply System costs associated with WNP-1 and WNP-3, conservation costs, and the cost of the section 5(c) residential exchange. Chamberlain et al., CEC, E-CC-01, 49; Initial Brief, CEC, B-CC-01, 10; Exceptions, CEC, R-CC-01, 5-6. See also SCE, WP-87-7229, 17. CPUC argues that the only costs BPA incurs in providing nonfirm energy service are the variable costs of operating hydroelectric and thermal facilities. Initial Brief, CPUC, B-CP-01, 7; Exceptions, CPUC, R-CP-01, 5. CPUC further argues that other nonproduction costs should not be included. Initial Brief, CPUC, B-CP-01, 8; Exceptions, CPUC, R-CP-01, 5.

Besides improperly including residential exchange costs, CEC and the CPUC argue the cost of the exchange resources assigned to nonfirm energy has been artificially inflated. Initial Brief, CEC, B-CC-01, 13; Initial Brief, CPUC, B-CP-01, 8. The true or "out of pocket" cost of exchange resources, CEC asserts, is not the total or gross cost but rather the net cost of the exchange (gross cost of the exchange less the revenues received from the exchange purchases). Initial Brief, CEC, B-CC-01, 13.

WNP-1, WNP-3, Conservation, Fish & Wildlife, and Transmission Costs

In each of BPA's rate cases beginning in 1981, and again in the 1981 and 1982 section 7(k) proceedings at FERC, BPA has demonstrated that in an integrated hydroelectric and thermal generation system, it is extremely difficult to identify specific resources that are responsible for a nonfirm energy sale at any given time. This is caused in part by the storage capabilities and operating flexibilities inherent in the hydro portion of the combined system. The output from a hydro system is in part a function of the planning and operation of all system resources. Metcalf/Griffin, BPA, E-BPA-24, 3; Griffin, BPA, TR 2361-2362. FERC recognized this unique characteristic of BPA's system in Opinion 250, which approved the NF-1 and NF-2 rates. U.S. Department of Energy, Bonneville Power Administration, 36 FERC ¶61,335 (1986).

BPA has used an average cost of production methodology since 1982. The cost methodology employed to determine the average cost of nonfirm energy production in previous rate cases has been to divide BPA's resource and operation costs assignable to nonfirm energy by BPA's total system load. Metcalf/Griffin, BPA, E-BPA-24, 3. FERC approved the reasonableness of this methodology following review of BPA's NF-2 Standard rate. U.S. Department of Energy, Bonneville Power Administration, 36 FERC ¶61,335 (1986). Subsequent nonfirm rates--NF-83, NF-85, and NF-85 modified--also follow this methodology. Metcalf/Griffin, BPA, E-BPA-24, 3. BPA has again used this methodology to determine the average cost of NF-87 nonfirm energy. Id., 3.

California parties and participants raise the same arguments against including Supply System costs, conservation costs, fish and wildlife costs, and transmission costs that were raised in previous rate cases and section 7(k) proceedings. 1983 Rates ROD, WP-83-A-02, 294; 1985 Rates ROD, WP-85-A-02, 293-294 and 298-299. FERC has explicitly considered and rejected all of these arguments. U.S. Department of Energy, Bonneville Power Administration, 29 FERC ¶63,039 (1984); U.S. Department of Energy, Bonneville Power Administration, 36 FERC ¶61,335 (1986); U.S. Department of Energy, Bonneville Power Administration, 39 FERC ¶61,033 (1987). "The California Parties' arguments that BPA's nonfirm rates may not include the costs for BPA's conservation programs, fish and wildlife programs and the uncompleted WPPSS nuclear plants because these costs are not associated with the production of energy were considered and rejected in Opinion 250." 39 FERC Mimeo at 5.

CEC, CPUC, and SCE do not raise any new factual material or provide any demonstration that circumstances have changed such that there is a compelling reason to revisit these issues in this proceedings. BPA assumes that these parties raise these issues for the purpose of preserving their litigation positions for further review in the Ninth Circuit.

Residential Exchange Costs

In its initial proposal, BPA included the residential exchange resource costs in the determination of the average cost of nonfirm energy. BPA noted that the costs of the residential exchange are purchase power costs that must be recovered from current ratepayers. Metcalf/Griffin, BPA, E-BPA-24, 4.

California parties and participants (CEC, CPUC, and SCE) generally oppose inclusion of residential exchange costs in the calculation of the average cost of nonfirm energy. These parties variously argue that FERC has ruled Congress intended BPA's regional customers to pay for the cost of the exchange, that California customers receive no benefit from the exchange, and that the exchange is a pure subsidy involving neither a resource acquisition nor the production of nonfirm energy on BPA's system. Initial Brief, CEC, B-CC-01, 11, 13; Exceptions, CEC, R-CC-01, 7-8, 13; Initial Brief, CPUC, B-CP-01, 8; Chamberlain et al., CEC, E-CC-01, 50; SCE, WP-87-7229, 21.

NWP, DSIs and WPAG support inclusion of exchange costs in nonfirm energy rates and oppose BPA's draft decision excluding these costs. NWP argues that FERC has not ruled on the question of whether these costs may be included in nonfirm rates after July 1985, that a recent Ninth Circuit opinion indicates these costs should be recovered from all BPA's customers, that the residential exchange may affect the production of nonfirm energy, and that the residential exchange was intended to be an exchange of power. NWP, WP-87-M-100, 7; Exceptions, NWP, R-NP-01, 3 and 10.

The parties have raised essentially two issues regarding whether residential exchange costs should be included in the calculation of the average cost of nonfirm energy. First, the parties raise the issue of whether BPA may legally assign residential exchange costs to nonfirm energy rates.

Second, the parties raise the issue of whether exchange costs should be allocated to nonfirm energy rates. These issues will be addressed separately below.

a. Legal Considerations

CEC and SCE allege that BPA's initial decision including residential exchange costs in nonfirm energy rates improperly construes FERC's decision in Opinion 250. Chamberlain et al., CEC, E-CC-01, 50; SCE, WP-87-7229, 21. CEC argues that FERC's ruling in Opinion 250-A clearly indicated that "Congress intended to confine" the allocation of residential exchange costs to BPA's DSI and other Northwest customers. Initial Brief, CEC, B-CC-01, 11.

NWP disagrees and argues that FERC's ruling on exchange costs applies only to pre-1985 rates and not to rates established after July 1, 1985. NWP, WP-87-M-100, 6. NWP notes that FERC relied upon the language of section 7(c) in Opinion 250, and that section 7(c) merely directs the Administrator to collect the cost of the residential exchange from DSIs for the period prior to July 1, 1985. NWP argues that the language of section 7(c) does not contain any requirement that the cost of the exchange be borne solely by the DSIs after July 1, 1985. Id., 7. WPAG agrees and concludes that the reason for excluding exchange costs no longer exists. Exceptions, WPAG, B-WA-02, 26. NWP further argues that excluding residential exchange costs from nonfirm energy rates conflicts with the Ninth Circuit's decision in Atlantic Richfield v. BPA (83-7971 et al., decided June 3, 1987). Exceptions, NWP, R-NP-01, 3 and 10.

CEC disagrees that FERC's decision makes this pre- and post-July 1, 1985 distinction. CEC states that "the FERC refers generically to Congress' intent that the DSIs and other Northwest customers pay the cost of the residential exchange." Initial Brief, CEC, B-CC-01, 12. CEC argues that FERC's reasoning that Congress did not intend to saddle California ratepayers with the cost of a Northwest subsidy is supported by the fact that the exchange program was designed to benefit Northwest purchasers, not California ratepayers. Id., 13.

For the following reasons, BPA concludes that FERC's decisions in Opinions 250 and 250-A determined only that the costs of the residential exchange should be allocated to the DSIs prior to July 1, 1985. The language of Opinion 250 makes a clear pre- and post-1985 distinction. In that opinion, FERC held that "Congress intended that BPA was to recoup its losses resulting from these agreements primarily by charging higher rates to its direct service industrial customers (DSIs) until July 1, 1985." 36 FERC at 61,812. Opinion 250-A reaffirmed the Commission's earlier decision approving BPA's 1981 and 1982 nonfirm energy rates. 39 FERC ¶61,033, Mimeo at 8.

In Opinion 250-A, FERC concluded that its "review of the legislative history of section 5(c) [sic] satisfies us that Congress intended to confine the allocation of the costs of the residential exchange program to BPA's DSI customers and other Northwest customers." Id. This language appears to support the CEC's argument that FERC addressed allocation of exchange costs to nonfirm rates both before and after July 1, 1985. For two reasons, however, BPA concludes that the Commission did not address whether these costs should

be allocated to nonfirm energy rates after July 1, 1985. First, as NWP notes, FERC has set for briefing the issue of whether including exchange costs in post-1985 rates is consistent with Opinion 250. U.S. Department of Energy, Bonneville Power Administration, 39 FERC ¶61,097, 271-72 (1987). This implies FERC's decisions on the 1981 and 1982 rates address only residential exchange cost allocation prior to July 1, 1985.

Second, the Commission's decision in Opinion 250-A reaffirming Opinion 250 relied on legislative history of section 7(c). This legislative history, however, is clear in only one respect: Congress intended the DSIs to pay for the majority of the costs of the residential exchange prior to July 1, 1985. See e.g., H.R. Rep. No. 976, 96th Cong., 2d Sess. (Pt. II) 35 ("[t]he direct-service industrial customers of BPA are required to pay the costs of the exchange during its initial years while a rate ceiling protects the customers of preference customers during later years."); H.R. Rep. No. 976, 96th Cong., 2d Sess. (Part 2) 61 ("The cost of the exchange during the first five years is charged to the rates applicable to DSIs under the section 7(c)(1)(A)."); and S. Rep. No. 272, 96th Cong., 1st Sess., 59 ("(1) 1980-81 through 1984-85. The industrial rates will be set to the levels estimated to be necessary to offset the increased costs to BPA which result from the purchase of IOU exchange power to the extent those costs are not covered through rates applicable for the other classes of power sold by BPA.")(emphasis in original). This legislative history is replete with reference to primary DSI responsibility for exchange costs prior to July 1, 1985, but is noticeably devoid of any reference to how exchange costs are to be recovered after July 1, 1985.

While BPA agrees with NWP's conclusion that FERC has not addressed whether exchange costs may be included in nonfirm energy rates after July 1, 1985, BPA does not agree with NWP's argument that these costs must be allocated to nonfirm energy rates. NWP argues that the Ninth Circuit in Atlantic Richfield v. BPA, No. 83-7971 (June 3, 1987), requires BPA to allocate residential exchange costs to nonfirm energy rates after July 1, 1985. Specifically, NWP relies on language in the Court's opinion that states ". . . after July 1, 1985, BPA must equitably apportion any subsidy costs to all of BPA's customers." Slip Op. at 7. It is incorrect , however, to argue that this language requires allocation of exchange costs to any rate. The phrase "must equitably apportion . . . to all of BPA's customers" is not synonymous with "must apportion to all customers." The crucial word in the Ninth Circuit's language is "equitably." To equitably apportion residential exchange costs means nothing more nor less than that BPA has the discretion to allocate all or none of these costs to additional rates after July 1, 1985. See American Paper Institute v. American Electric Power Service Corp., 461 U.S. 402, 406-418 (1983). An equitable allocation can mean an allocation of no exchange costs to nonfirm energy rates.

WPAG argues that the exchange is treated as a purchase and sale of power by the Northwest Power Act for purposes of developing BPA's rates. Exceptions, WPAG, B-WA-02, 25. See also, NWP, WP-87-M-100, 7. WPAG argues that the exchange should not be distinguished from other system costs, such as fish and wildlife costs, which are properly includable in the cost of nonfirm energy. Exceptions, WPAG, B-WA-02, 25. WPAG is correct that the Northwest

Power Act treats the exchange as a purchase and sale of power. BPA currently allocates residential exchange costs to all firm power rates on that basis. There is no Northwest Power Act requirement, however, that residential exchange costs be allocated to nonfirm energy rates.

BPA's nonfirm energy rates are established pursuant to section 7(k) of the Northwest Power Act. 16 U.S.C. 839e(k). Section 7(k) merely provides that nonfirm energy rates shall be consistent with the Project Act, the Flood Control Act, and the Federal Columbia River Transmission System Act. Id. Together, these statutes require that BPA's nonfirm energy rates be consistent with four standards that BPA's nonfirm rates recover the cost of generation and transmission of electric energy, encourage widespread use of Bonneville power, be as low as possible consistent with sound business principles, and protect the interests of the United States in amortizing its investment. U.S. Department of Energy, Bonneville Power Administration, 27 FERC 61,251, 61-475-476 (1984). These standards neither prohibit nor require the allocation of exchange costs to nonfirm energy rates. The determination of whether these costs should be allocated to nonfirm energy rates must depend on other factors.

b. Should Exchange Costs be Allocated to Nonfirm Energy Rates

CEC and CPUC reason that exchange costs should be excluded from the calculation of the NF-87 Standard rate. First, CPUC and the CEC argue that exchange costs are inappropriately assigned to nonfirm energy rates because the exchange is unrelated to the production of nonfirm energy. Initial Brief, CEC, B-CC-01, 6-7; Initial Brief, CPUC, B-CP-01, 8. Second, these regulators argue that the residential exchange can benefit only ratepayers of Pacific Northwest utilities, and cannot benefit California ratepayers. Initial Brief, CEC, B-CC-01, 13; Initial Brief, CPUC, B-CP-01, 8.

NWP disagrees that the residential exchange does not contribute to the availability of nonfirm energy. NWP, WP-87-M-100, 7. The existence of the residential exchange program, NWP asserts, may affect the availability of nonfirm energy. Id. NWP argues that absent the exchange, BPA's preference customers' rates would be lower. Lower rates would in turn affect PF loads and ultimately the operating levels of the regional hydro and thermal plants. Id. NWP further argues that the exchange affects the regional IOUs' operations. Under this scenario, NWP postulates that, absent the exchange, the regional IOUs would increase purchases of BPA's lower cost power instead of using power from their own generation, thus decreasing the amount of nonfirm energy available to California. Id., 7-8.

NWP's arguments that the residential exchange may contribute to the availability of nonfirm energy are too speculative to be convincing. NWP relies on the premise that a change in BPA's wholesale power rates to PF customers results in a change in PF loads. In theory NWP is correct that loads respond to changes in rates. However, the evidence presented in this case suggests that the PF load response due to PF rate changes is uncertain. Melton/Armstrong, BPA, E-BPA-53, 4. See Chapter II, section D for a more detailed discussion of PF price elasticity. In addition, the public agency PF rate is protected from significant exchange costs by the 7(b)(2) rate test.

16 U.S.C. 839e(b)(2). Nevertheless, even if the residential exchange does significantly impact the amount of regional firm load, NWP's argument ignores current firm power surpluses on BPA's system. Until firm surpluses expire, an increase in BPA's regional loads will not necessarily lead to a decrease in the availability of nonfirm energy. As the CEC correctly notes, NWP's arguments are not based on any evidence presented in this case but rather are based on speculation. Exceptions, CEC, R-CC-01, 9. The evidence in this case suggests that the residential exchange has very little, if any, impact on the availability of nonfirm energy. BPA has never taken the position that the residential exchange does materially contribute to the availability of nonfirm energy.

Regarding CEC's and CPUC's contention that the residential exchange can benefit only Northwest ratepayers, NWP disputes the conclusion that the exchange is purely an intraregional subsidy. NWP argues that had Congress intended the exchange as nothing more than a subsidy, the Northwest Power Act section 5(c)(5) provision for "in lieu purchases" of non-exchange power would not have been added. Id., 7. NWP is correct that in a situation where BPA implements or considers implementing the "in lieu purchase provision," the residential exchange has many aspects of a real sale and purchase. Under current circumstances, however, when BPA is contractually required to give 7-year notice of implemention of the "in lieu" provisions, the exchange more resembles a pure subsidy program than a program that affects BPA's loads and resources. Currently the residential exchange does not result in a net energy flow between BPA and a exchanging utility. Griffin, BPA, TR 2318.

The evidence in this record supports the arguments that the residential exchange is a subsidy program that does not contribute to the availability of nonfirm energy. However, BPA does not agree with the logic that only the costs associated directly with the production of nonfirm energy, or only costs that directly benefit nonfirm purchasers, may be recovered through nonfirm energy rates. If this logic were applied to each of BPA's rates, BPA could never achieve the requirement of section 7(a) that BPA's rates recover BPA's total revenue requirement. In addition, FERC has specifically rejected the notion that only costs associated with the production of nonfirm energy may be allocated to nonfirm energy rates. In Opinion 250, FERC held that even though programs do not directly lead to the availability of nonfirm energy on BPA's system, some costs are required of BPA and therefore may be recovered through nonfirm energy rates. U.S. Department of Energy, Bonneville Power Administration, 36 FERC 61,335, 61,810.

CEC notes, however, that for many years BPA did not include exchange costs in the calculation of nonfirm energy rates. Initial Brief, CEC, B-CC-01, 11. BPA included these costs in the 1985 nonfirm energy rates in response to Judge Miller's Initial Decision, which was an extremely important decision of first impression regarding BPA's nonfirm energy rates. 1985 Rates ROD, WP-85-A-02, 300-301. Judge Miller's comprehensive 116 page decision recommended disapproval of BPA's 1981 and 1982 nonfirm energy rates because BPA failed to include in its rates all costs, specifically residential exchange costs, that should have been allocated to those rates. U.S. Department of Energy, Bonneville Power Administration, 29 FERC 63,069, 65,095 and 65,113 (1984). Since the 1985 rate case, however, the Commission approved BPA's 1981 and 1982

nonfirm energy rates as reasonable. U.S. Department of Energy, Bonneville Power Administration, 36 FERC 61,335, 61,819 (1986). As noted above, BPA does not believe the Commission ruled that BPA could not assign exchange costs to nonfirm energy rates after July 1, 1985, but merely ruled that BPA's 1981 and 1982 decisions excluding these costs from nonfirm energy rates were reasonable. Nevertheless, allocating these costs to the 1985 nonfirm rates was a significant departure from previous nonfirm energy rates and was predicated on the expectation that FERC might approve Judge Miller's decision and require BPA to allocate these costs to future nonfirm energy rates.

The parties have raised good reasons both to include and exclude residential exchange costs from nonfirm energy rates. BPA has relied on some of these reasons in the past both to exclude exchange costs in the 1981, 1982, and 1983 rates, and to include them in the 1985 rates. For a number of reasons, however, BPA will not include these costs in nonfirm energy rates.

First, in assigning costs, a number of factors must be considered including the value to the purchaser. BPA sells nonfirm energy in an increasingly competitive economy energy market. Inclusion of exchange costs in BPA's 1985 rates made that cost-based rate uneconomic in most instances, forcing BPA to an emergency rate reduction in 1986. For example, in 1986 BPA's average nonfirm energy rate was 13.5 mills per kilowatthour, almost a full 10 mills below the cost of nonfirm energy. Griffin/Metcalf, BPA, E-BPA-58, 13. Inclusion of residential exchange costs in this rate period results in an average cost of nonfirm energy at about the same 1985 level. This level, however, is significantly above the level BPA reasonably expects can be recovered or will be economic, since BPA forecasts fuel prices for the rate period only slightly higher than the prices in 1986.

Second, another ratemaking goal is the goal of designing rates that minimize contentiousness. While BPA does not agree with California perceptions that California utilities have been overcharged by BPA, this perception is replete in the testimony, briefs, and comments filed by California parties and participants in this proceeding. Chamberlain et al., CEC, E-CC-01, 5-6; E-CC-02, 24-25; CEC, Electricity Report, pp. 5-23 through 5-26; SCE, WP-87-7229, 2-3; Initial Brief, CEC, B-CC-01, 7; Exceptions, CEC, R-CC-01, 4 footnote 1; Initial Brief, CPUC, B-CP-01, 7-12; PG&E, WP-87-7494, 1, 3-4. BPA believes that its decision to include exchange costs in the calculation of the NF-85 Standard rate was a significant factor contributing to increasing hostilities between BPA, its California customers, and its Northwest customers. These interregional hostilities benefit neither California nor the Northwest.

Decision

Supply System costs, fish and wildlife costs, conservation costs, and FCRTS costs will be included in the determination of the average cost of nonfirm energy. Residential exchange costs will not be included in the determination of the average cost of nonfirm energy.

Issue 2

Should the NF-87 rate schedule allow BPA to offer nonfirm energy at prices above the average cost of nonfirm energy?

Evaluation of Positions

BPA's proposed NF-87 rate permits BPA to offer energy at rates both above and below the average cost of nonfirm energy. BPA, E-BPA-06, 59. One of BPA's objectives in designing this rate, as with any other rate based on cost of service, is to attempt to collect the costs of providing this service over time. Metcalf/Griffin, BPA, E-BPA-24, 10.

NWP encourages rate flexibility as a means of collecting nonfirm energy revenues approximately equal to the cost of producing nonfirm energy. Initial Brief, NWP, B-NP-01, 1. NWP supports the ability to set prices above the average cost of nonfirm energy (upward flexibility). Opatrny/Peters, NWP, E-NP-01, 3. Because the market may often require BPA to sell nonfirm energy below the average cost of production, NWP notes, upward flexibility enhances BPA's ability to recover the cost of making nonfirm energy available. Id., 3.

CEC, SCE, PSP&L, WWP, and MPC oppose upward flexibility on the grounds that such pricing flexibility will adversely impact BPA's customers and is inconsistent with legal precedent and BPA's statutory directives for cost-based rates. Chamberlain et al., CEC, E-CC-01, 47-48; Initial Brief, CEC, B-CC-01, 7-9; Exceptions, CEC, R-CC-01, 4, n. 1; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 11; Exceptions, PSP&L et al., R-PS/MS/WP-01, 16. SCE, WP-87-7229, 12-13; WP-87-7655, 47.

Legal Objections to Upward Flexibility

CEC and SCE contend that pricing above cost is not supported by other FERC precedent. Chamberlain et al., CEC, E-CC-01, 47; Initial Brief, CEC, B-CC-01, 7-9, and 47; SCE, WP-87-7229, 12-13; SCE, WP-87-7655, 2. In particular, SCE cites Federal Power Act cases for the proposition that BPA may not develop cost-based rates that permit sales above full cost. However, Federal Power Act standards do not govern BPA's section 7(k) rates. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1113, n. 6 (9th Cir. 1984). Most recently, FERC concluded that BPA's nonfirm rates are "not subject . . . to any substantive considerations of the Federal Power Act." 52 FR 20704, 20706 (1987).

PSP&L, MPC, and WWP (Northwest purchasers) argue that upward flexibility violates the statutory standard that BPA's rates be "as low as possible." Initial Brief, PSP&L et al., B-PS/MP/WP-01, 11. BPA disagrees that upward flexibility violates BPA's ratemaking standards. BPA's nonfirm energy rates are established pursuant to section 7(k) of the Northwest Power Act. 16 U.S.C. 839e(k). Section 7(k) requires that nonfirm energy rates be consistent with the Bonneville Project Act, the Flood Control Act, and the Federal Columbia River Transmission System Act. Id. FERC has held that these statutes cumulatively require that BPA's nonfirm energy rates be consistent with the following four standards:

(1) Having regard to the recovery of the cost of generation and transmission of such electric energy;
(2) So as to encourage the most widespread use of Bonneville power;
(3) To provide the lowest possible rates to consumers consistent with sound business principles; and
(4) In a manner which protects the interests of the United States in amortizing its investments within a reasonable period.

U.S. Department of Energy, Bonneville Power Administration, 27 FERC 61,251, 61,475 - 476 (1984).

Northwest purchasers' argument that upward flexibility violates the requirement that BPA's rates be "as low as possible" selectively ignores that this requirement is modified by the concurrent requirement these low rates also be "consistent with sound business principles." Id. These four legislative standards cannot be read in isolation from the other standards. Cumulatively, these standards require that nonfirm rates be as low as possible consistent with sound business principles so long as they are cumulatively high enough to recover the Federal debt plus other costs, while encouraging the widest possible use of electricity. Rates that cannot by design recover cost over time would be inconsistent both with the requirement that the rates recover costs and protect the Federal investment and with the requirement that they be consistent with sound business principles.

However, these Northwest purchasers also argue that a recent FERC decision approving BPA's 1983 nonfirm energy rates indicates that BPA can meet its cost recovery requirement through a "single standard average cost nonfirm rate." Initial Brief, PSP&L et al., B-PS/MP/WP-01, 11; Exceptions, PSP&L et al., R-PS/MP/WP-01, 16. These parties incorrectly construe the Commission's decision.

In approving NF-83, the Commission approved upwardly flexible nonfirm energy rates as consistent with section 7(k) of the Northwest Power Act. In Opinion 271, the Commission determined that BPA's NF-83 Standard rate exceeded the costs attributable to nonfirm energy because it improperly included the cost to BPA of industrial reserves. U.S. Department of Energy, Bonneville Power Administration, 39 FERC 61,069, Mimeo at 16. Nevertheless, the Commission approved NF-83 because "average revenue from sales of nonfirm energy" did not exceed its calculation of BPA's costs (emphasis added). Id. This decision is consistent with the Commission's previous decision approving BPA's variable industrial (VI-86) power rate, which also permits upward and downward flexibility. The Commission approved VI-86 so that BPA could recover the cost of that power over time. Order Confirming and Approving Rates On A Final Basis and Terminating Dockets, Docket Nos. EF85-2011-001 et al., (April 29, 1987), Mimeo at 16.

Other Objections to Upward Flexibility

CEC strongly opposes upward pricing flexibility for other reasons. First, the unlimited upward flexibility provided by the NF rate cap, CEC argues,

"results in rates that have no relationship whatever to the cost of producing (nonfirm) energy." Id., 47. In addition, the CEC notes that the rate schedule does not contain any safeguard to prevent BPA from unnecessarily offering rates above cost. Id., 53. Second, CEC argues that the unlimited upward flexibility allowed by the NF rate cap will result in some ratepayers subsidizing other ratepayers. Specifically, CEC asserts that California ratepayers will bear the burden of cost recovery for below-cost sales made in the PNW. Id., 48. For these reasons, CEC concludes that the fully distributed cost of nonfirm energy should serve as the ceiling on a cost-based rate, not as an average revenue target. Id., 46.

PSP&L, WWP, and MPC (Northwest purchasers) agree with CEC; selling nonfirm energy at rates above cost will result in cross-subsidies between customer classes. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 11. Northwest purchasers conclude that upward flexibility is in reality a "revenue maximizing" objective. Id.

The arguments advanced by CEC, PSP&L, WWP, and MPC to eliminate all upward pricing flexibility imply that full cost recovery is an inappropriate objective of a cost-based nonfirm energy rate. Apparently they believe that full cost recovery should be subordinated to a goal of never selling a unit of nonfirm energy above cost. This focus on unit sales to the detriment of cost recovery is inconsistent both with BPA's statutory duty to recover all of its costs and with the notion that economy energy purchases are entirely voluntary. The non-captive nature of economy energy markets alleviates the need for the cost-based strictures usually applied to rates for sale to captive customers.

The other problems associated with upward flexibility identified by CEC, the uncoupling of the rate charged from cost and the potential for inter-class subsidies, are not persuasive arguments for entirely eliminating upward flexibility. First, it is true that upward flexibility may mean that the actual rates offered in any one hour may not exactly equal the cost of nonfirm energy. However, this is also true when rates are offered below cost. CEC, PSP&L, WWP, and MPC apparently do not object to below-cost sales nothwithstanding that below-cost sales jeopardize BPA's ability to collect its revenue requirement. Second, the fact that the rates offered in any hour are not exactly equal to costs does not support the conclusion that the relationship between the actual rates offered and the cost of nonfirm energy is severed. Griffin/Metcalf, BPA, E-BPA-58, 4. To the extent sales can be made at rates as close as possible to cost, the correlation between the cost of nonfirm energy and the revenues realized will be greater. Id. Moreover, as noted above, FERC has approved upward flexibility when average revenues do not exceed cost.

CEC's second concern, that upward flexibility will force PSW purchasers to pay higher rates to make up for below cost sales to PNW purchasers, is academic for this rate period. Given current forecasts of gas and oil prices, BPA expects that most PSW sales will be at rates below the full cost of nonfirm energy. Griffin/Metcalf, BPA, E-BPA-58, 3. Over the 2-year test period, the average rate paid by PSW purchasers is forecasted to be 3 to 4 mills per kilowatthour below the cost of nonfirm energy. Id., 3. In other

words, given likely market conditions, BPA expects that sales to PSW customers will be below full cost. CEC's assertion that PSW customers will subsidize PNW customers when both are purchasing below cost is speculative and unsupported by any evidence on the record.

The issue of inter-regional subsidies becomes germane when decremental costs in the PSW are expected to be high. However, this can be resolved by limiting the amount of upward flexibility in the rates. It has never been BPA's position that the NF rate should be designed to recover the average cost of nonfirm energy from every unit sold. In determining the NF-85 Standard rate, revenue underrecoveries from low-cost nonfirm energy sales were not included in the adder for below cost sales. 1985 Rates ROD, WP-85-A-02, 308. Low-cost sales were not included because these sales are the lowest priority nonfirm sales. BPA reasoned that excluding such sales prevented PSW purchasers from bearing the cost-recovery responsibility for sales made exclusively to PNW utilities. Id. If future market conditions are such that the majority of forecasted PSW sales would be economic at cost, but some PSW below-cost sales were expected, the NF rate would be designed to collect the average cost from all PSW sales alone. It is not BPA's intent to design the NF rate so that above-cost PSW sales subsidize below-cost sales in the PNW. Metcalf, BPA, TR 2336. For this rate period, however, it is precisely because BPA expects low decremental costs and volatile gas and oil prices that greater pricing flexibility is warranted to meet BPA's cost recovery objective.

CPUC, PSP&L, WWP, and MPC further argue that BPA does not have a revenue requirement associated with the production of nonfirm energy. Exceptions, PSP&L et al., R-PS/MP/WP-01, 16; Exceptions, CPUC, R-CP-01, 3. Federal resources, CPUC, PSP&L, WWP, and MPC assert, are planned and operated to supply firm power requirements. Id., 4; Exceptions, PSP&L et al., R-PS/MP/WP-01, 16. The production of nonfirm energy, CPUC concludes, is but "an incidental by product" of the planning and operation of the Federal system. Exceptions, CPUC, R-CP-01, 5. What this means, CPUC states, is that the notion that BPA ever sells nonfirm energy below cost is merely a fallacy. Id., 3.

These arguments offered by CPUC and some Northwest purchasers are not new, but merely revisit past arguments that BPA's nonfirm energy rates must be based on the incremental cost of nonfirm energy service. See 1983 Rates ROD, WP-83-A-02, 290-291; 1985 Rates ROD, WP-85-A-02, 276-281 and 305-306. This argument was rejected by FERC in recent 7(k) hearings on NF-1 and NF-2. U.S. Department of Energy, Bonneville Power Administration, 36 FERC ¶61,335 (1986). Given that these arguments have been carefully considered and rejected by BPA and the FERC in past proceedings, a detailed evaluation of these arguments is unnecessary and redundant.

Last, SCE argues that pricing nonfirm energy above cost is inconsistent with BPA's May 7, 1987 testimony before Congressional oversight hearings on the Intertie Access Policy. SCE, WP-87-7655, 2. As quoted by SCE, the Administrator testified:

> "As for nonfirm energy, BPA will continue to structure its rate to collect through sales over the Intertie no more than the costs FERC has determined are attributed to nonfirm energy. Hence, as has been the case in the past, BPA will continue to set an upper limit on its nonfirm (energy) rate, regardless of the fact that gas and oil prices, or other California generation costs, may rise in the future."

SCE believes that in this statement BPA committed to charge no more than the average cost of nonfirm energy. Id., 2. SCE misunderstands the testimony. The Administrator's commitment was to design the Nonfirm rate to recover over time the average cost of nonfirm energy from sales over the Intertie. This was not a commitment to restrain each nonfirm energy unit price to cost or less.

Decision

NF-87 will permit pricing flexibility above the average cost of nonfirm energy.

Issue 3

What is the appropriate upper limit for the NF-87 Standard rates?

Evaluation of Positions

BPA's initial proposal set the upper limit of the NF-87 Standard rate equal to the long-term rate cap. Metcalf/Griffin, BPA, E-BPA-24, 7. The NF rate cap reduces the risks of establishing an upper limit based on uncertain market conditions and provides flexibility to respond to changing market conditions. Id., 10. In addition, for this rate period, expected market conditions are such that cost recovery cannot be demonstrated on a forecasted basis, regardless of the upper limit set for the NF rate. Griffin/Metcalf, BPA, E-BPA-58, 2. Because the NF rate cap is proposed to apply to all nonfirm energy rates, the NF rate cap was selected as the appropriate upper bound on the NF-87 rate in order not to forgo sales at higher rates if market conditions allowed. Metcalf/Griffin, BPA, E-BPA-24, 10.

Parties in this proceeding strongly oppose an upper limit on BPA's nonfirm energy rates tied to PSW decremental costs. Chamberlain et al., CEC, E-CC-01, 33; Lauckhart, PSP&L/MPC/WWP, E-PS/MP/WP-01, 3.

CEC questions whether the degree of upward flexibility provided by the NF rate cap is necessary to achieve BPA's cost recovery objective. Chamberlain et al., CEC, E-CC-01, 34. BPA's cost recovery objectives can be met, CEC asserts, with an upper bound considerably less flexible than the proposed NF rate cap. Id. Specifically, CEC argues that an upper limit of 120 percent of BPA's costs is sufficient to allow cost recovery. Id., 38.

While NWP generally supports the concept of upward pricing flexibility in the NF rate, they also appear to be concerned with the degree of upward flexibility the NF rate cap allows. NWP proposes constraining upward flexibility equal to 75 percent of the purchasing region's system-wide decremental cost. Brattebo et al., NWP, E-NP-03, 3; Initial Brief, NWP, B-NP-01, 4.

There are concerns in both regions regarding use of the NF rate cap as the limit on NF-87 rates. Chamberlain et al., CEC, E-CC-01, 35; Lauckhart, PSP&L et al., E-PS/MP/WP-01, 3. The fundamental concern in California appears to be that pricing flexibility up to the NF rate cap would permit BPA to follow California decremental costs as they rise, and thereby subsidize Northwest purchases at lower-rate sales. Chamberlain et al., CEC, E-CC-01, 48; Initial Brief, CEC, B-CC-01, 17. The fundamental concern in the Northwest appears to be that pricing flexibility up to the rate cap would permit California customers to outbid Northwest purchasers for BPA's nonfirm energy such that this resource would be uneconomic to them at the going rate. Brattebo et al., NWP, E-NP-03, 2; Initial Brief, NWP, B-NP-01, 2; Lauckhart, PSP&L et al., E-PS/MP/WP-01, 3, 11, and 18-23; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 9; Exceptions, PSP&L et al., R-PS/MP/WP-01, 16.

The concerns expressed by both regions can be addressed by fixing the upper limit at a predetermined level which is therefore not affected by changes in PSW decremental fuel costs. A fixed upper limit provides both regions with assurance that prices for nonfirm energy will be offered at levels economic to both regions. In addition, a fixed upper limit mitigates the potential for interregional subsidies. Establishing an upper limit for the NF-87 Standard rate during this rate period is complicated, however, by the fact that expected market conditions, not the upper limit, preclude recovering the cost on average from PSW nonfirm energy sales. During this rate period the majority of sales to the PSW are projected at rates below cost. Under current market expectations in those few instances when above-cost sales are possible, the expected prices for and the amounts of these sales are insufficient to counter the volume of PSW below-cost sales. This raises a dilemma because while unlimited upward flexibility is inconsistent with a cost recovery objective, there is no upper limit which can be shown on a forecasted basis to provide for cost recovery.

In the Draft ROD, BPA determined that the CEC's proposal to limit BPA's nonfirm energy rates to 120 percent of BPA's cost is a reasonable approach to establishing a fixed upper limit in the short run to address the concerns expressed by the parties. DROD, WP-87-A-01, 136. An upper limit based on 120 percent of BPA's average cost of nonfirm energy is straightforward and less complicated to administer than BPA's proposed rate cap. Melton et al., BPA, E-BPA-59, 4. A limit based on 120 percent of the cost of producing nonfirm energy establishes a limit based solely on BPA's costs and removes PSW decremental costs from the determination of a upper limit. Furthermore, the 120 percent pricing constraint maintains a range of prices for nonfirm energy that is economic in both regions. While BPA is not prepared to adopt this type of pricing limitation for a 12-year period, the concerns that this type of pricing limitation may prove too restrictive in the longrun do not apply in the shortrun. The upper limit based on 120 percent of BPA's costs applies

only to BPA's cost-based rate for this rate period, and not the SS-87 rate. Thus the share-the-savings rate would not be unduly restricted.

CEC supports BPA's decision to limit all nonfirm energy sales during this rate period to 120 percent of the average cost of nonfirm energy. Exceptions, CEC, R-CC-01, 10. PPC, APAC, MWP, and WPAG oppose this limitation on the NF rate. Exceptions, PPC, R-PP-01, 25-26; Exceptions, APAC, R-PA-01, 6-7; Exceptions, WPAG, B-WA-02, 28; Exceptions, NWP, R-NP-01, 4. NWP asserts that an upper limit tied to 120 percent of nonfirm energy costs precludes cost recovery. Exceptions, NWP, R-NP-01, 4. The limitation imposed on the NF rate, NWP stresses, is harmful to BPA and its customers. Id., 5. PPC concurs. Exceptions, PPC, R-PP-01, 26.

By imposing this upper limit, NWP asserts, BPA is unnecessarily forgoing revenues which could contribute to cost recovery. In fact, NWP points out that BPA forecasts prepared for this rate case indicate that sales at rates above the self-imposed 120 percent limit would be possible. Exceptions, NWP, R-NP-01, 5. While it is true that BPA projected some sales at prices above the 120 percent limitation, it is also true that sales at these levels were expected only in the last two months of the test period (August and September 1989). The additional revenue from these sales still would not allow BPA's cost recovery objectives to be realized.

As further evidence that the 120 percent limit may result in BPA forgoing revenues, NWP notes that some PNW utilities are currently selling nonfirm energy at prices fairly close to the 120 percent limit. Id. In addition, NWP cites a recent statement by SCE that its decremental costs presently are 30 mills per kilowatthour. Id. If NWP is correct that the market will allow rates at or close to the 120 percent upper limit when the rates go into effect, it is not clear how such a limit precludes cost recovery. Further, the 120 percent upper limit will not prevent offering nonfirm energy rates equal to 75 percent of California's decremental cost, as NWP proposes, if decremental costs are 30 mills per kilowatthour before adjustment for losses.

While BPA appreciates NWP's concerns that BPA not set an upper limit on its nonfirm energy rates that may in retrospect foreclose possible markets, NWP's proposed alternative to limit above cost pricing to 75 percent of the purchasing region's decremental cost is unworkable. Establishing a separate upper limit for each region, in effect, is just another variation of NWP's dual Standard rate proposal. A more detailed evaluation of NWP's dual Standard rate proposal is contained in section A.2., Issue 1. The same reasons for rejecting the dual Standard rate apply to separate rate limits for PNW and PSW nonfirm energy purchasers. An upper limit based on 120 percent of the average cost of nonfirm energy achieves the same objective as NWP's proposal, to keep the nonfirm energy rate within a range that is economic to the PNW purchasers.

PPC suggests that BPA's decision to limit the NF rate to 120 percent of cost is made in response to threats by California regulators. Exceptions, PPC, R-PP-01, 25. QFs will not affect the size of PSW markets for nonfirm energy, PPC argues, during the test period. Id., 26. Consequently, PPC asserts, BPA will not benefit from the 120 percent limit during the test

period. Id. PPC misconstrues the reason for the 120 percent limit. It is not proposed to address California regulators' long-term perceptions but rather to address concerns raised by both California and PNW utilities relating to use of the long-term rate cap to establish an upper limit on a cost-based rate.

WPAG expresses concern that the relationship between upward and downward pricing flexibility from the cost of nonfirm energy is asymmetrical. Exceptions, WPAG, B-WA-02, 28. The amount of downward flexibility, WPAG notes, is "virtually unlimited," while the amount of upward flexibility is considerably less. Id. WPAG's concern that the asymmetrical relationship between upward and downward pricing flexibility will over time result in a bias toward underrecovery as nonfirm energy costs change appears to based on a fundamental misunderstanding. Id. The 120 percent upper limit is applicable to only the current NF-87 rate and is separate and distinct from the long-term NF rate cap which applies for 12 years to all nonfirm energy rates. The 120 percent limit represents a reasonable approach to fix an upper limit for the nonfirm energy rate under conditions when there is no upper limit which can guarantee cost recovery.

Future nonfirm energy rates will continue be designed to recover on a forecasted basis the cost of nonfirm energy. Creating a symmetrical relationship between upward and downward pricing flexibility as suggested by WPAG has merit, but is unnecessary to meet BPA's cost recovery objective. The amount of upward pricing flexibility needed to make up for expected below-cost sales depends on: (1) the amount of below-cost sales; and (2) the rates at which these sales are made. For example, if few below-cost sales are expected or if the forecasted price for these sales is only slightly below the cost of nonfirm energy, the highest rate offered need not be equal to the difference in mills per kilowatthour between the nonfirm energy cost and the lowest rate expected during the rate period in order to meet BPA's cost recovery objectives on a forecasted basis.

Decision

Limiting upward flexibility of the NF-87 rate to 120 percent of the average cost of nonfirm energy provides sufficient upward flexibility in this rate period to enhance BPA's ability to recover the cost of nonfirm service. In addition, an upper limit based on 120 percent of the average cost of nonfirm energy addresses the concerns of parties in both regions that the rate may become uneconomic or cause interregional subsidies.

2. Nonfirm Energy Rate Design

NF-87 is BPA's cost-based rate for nonfirm energy transactions. Four rate components are included in the proposed NF-87 rate schedule--a Contract rate and three marketing rates. The marketing rates consist of the NF Standard rate, the Market Expansion rate, and the Incremental rate. Metcalf/Griffin, BPA, E-BPA-24, 6. The Standard rate is BPA's primary marketing rate for nonfirm energy. Only one Standard rate may be offered at any given time. Id. The Market Expansion rate is designed to allow BPA to reach additional

markets not economic at the prevailing Standard rate. Purchases under the Market Expansion rate are subject to resource prequalification and displacement criteria. More than one Market Expansion rate may be offered concurrently. Id., 7. The Incremental rate applies when (1) BPA has a specific discretionary resource available with incremental cost greater than the Standard rate, and (2) a purchaser desires to purchase the output of this resource. Id., 8.

NWP presented an alternative NF rate package consisting of two concurrent Standard rates, one Market Expansion rate, and two fixed displacement rates. The Standard rate under the NWP proposal equals the greater of 75 percent of each region's system-wide decremental cost or the average cost of nonfirm energy. The Market Expansion rate is a flexible rate set to maximize revenues below the cost of nonfirm energy but greater than 7.0 mills/kWh. The fixed displacement rates are set at 7.0 mills/kWh for coal displacement and 3.0 mills/kWh for nuclear displacement. While NWP proposed a complete rate package, each component is evaluated separately below.

Issue 1

Should BPA adopt separate Standard rates for the PNW and PSW regions?

Evaluation of Positions

BPA's proposed Standard rate serves as BPA's primary nonfirm energy marketing rate. BPA, E-BPA-06, 7. Offers of nonfirm energy, when available, will first be made at the Standard rate. Only one Standard rate will be offered at any given time. Id., 77. Under recent conditions of low decremental fuel prices in California coupled with large amounts of available nonfirm energy, BPA's practice generally has been to set the Standard rate equal to approximately 75 percent of the lowest-cost PSW resource BPA seeks to displace. Metcalf/Griffin, BPA, E-BPA-24, 15.

NWP's proposed alternative Standard rate allows for two rates, one to PNW and one to PSW utilities. The rate to each region, under the NWP proposed rate structure, is set at the greater of 75 percent of the region's system-wide decremental cost or the average cost of nonfirm energy. Brattebo et al., NWP, E-NP-03, 2. NWP proposed that offers of nonfirm energy first be made to the PNW utilities at the NW Standard rate. Id., 3. The NWP proposal places two restrictions on sales at the NW Standard rate. First, such sales are made only to serve "native load and firm contract obligations." Id. Second, PNW utilities purchasing at the NW Standard rate are prohibited from making simultaneous sales of nonfirm energy over the Southern Intertie. Id., 5. Nonfirm energy remaining after NW Standard rate subscriptions have been made, under the NWP dual standard rate scheme, will be sold at the PSW Standard rate. Id., 4. Nonfirm energy offered under the PSW Standard rate will be made first to PNW utilities without end-use restrictions, and then to PSW utilities. Id.

The DSIs, CEC, and WUTC oppose the dual Standard rate approach advanced by NWP. Schoenbeck, DSI, E-DS-04R, 5; Chamberlain et al., CEC, E-CC-02, 26. The

DSIs urge BPA to reject NWP's dual Standard rate proposal on the basis that it redefines regional preference. Schoenbeck, DSI, E-DS-04R, 4. NWP's dual Standard rate proposal, the DSIs argue, is detrimental to BPA and its customers in that it grants special privileges to some regional utilities at the expense of BPA's other customers, and possibly the U.S. Treasury. Id., 5. NWP's dual Standard rate proposal, the DSIs correctly note, would force BPA to offer nonfirm energy to the PNW at the average cost of nonfirm energy prior to making higher-cost sales in the PSW. Id., 5. In effect, the dual Standard rate structure results in inefficient resource operation. Griffin/Metcalf, BPA, E-BPA-58, 7. For instance, use of NWP's proposal under a limited supply condition may result in nonfirm energy being used to displace lower-cost PNW resources while higher-cost PSW resources will continue to operate. Id., 7. A single Standard rate achieves the greatest economic efficiency. If the decremental cost of the PNW resource is greater than BPA's Standard rate, economic purchases are not precluded by a single Standard rate. On the other hand, if the decremental costs of PNW resources are below the Standard rate, greater economic efficiency is achieved by displacing the higher-cost resources in the PSW. Id., 6.

NWP's rationale for proposing a dual Standard rate structure is unconvincing. NWP contends that a PNW Standard rate would be available to serve a PNW utility's firm obligations. Brattebo et al., NWP, E-NP-03, 3. If a PNW utility is relying on the economy energy market to meet its firm obligations and has no other options other than BPA's nonfirm energy, it is clear that a single Standard rate would not preclude PNW purchases. Nonfirm energy is first offered to PNW utilities. Metcalf/Griffin, BPA, E-BPA-24, 16. While it is true that when large amounts of nonfirm energy are available and the NF price is targeted to PSW markets, it is not clear why nonfirm energy used to serve PNW obligations would not be economic even at a rate targeted to the PSW. Griffin/Metcalf, BPA, E-BPA-58, 6.

Contrary to NWP's assertions that the dual Standard rate would enhance BPA's revenues, in fact it would erode BPA's nonfirm energy revenues. Id., 11. The DSIs accurately argue that the combination of regional price preference and freedom to operate displaced resources invites arbitrage. Schoenbeck, DSI, E-DS-04R, 6. NWP counters that their proposal is intended to hold BPA harmless from the resale of BPA's energy. Brattebo et al., NWP, E-NP-03, 5. For PNW Standard rate purchasers, NWP's proposal would impose restrictions on making simultaneous nonfirm sales or surplus sales less than 1 month in duration over the Southern Intertie. Id.

The DSIs assert that these constraints are easily circumvented. Schoenbeck, DSI, E-DS-04R, 6. First, as NWP acknowledges, utilities with reservoir storage could evade NWP's restriction on simultaneous hourly sales. Id., 7. The restriction on simultaneous sales would not prevent a PNW utility from purchasing nonfirm energy at the PNW Standard rate and storing that energy for a later sale to the PSW. Id.; Griffin/Metcalf, BPA, E-BPA-58, 7; Chamberlain et al., CEC, E-CC-02, 27. Second, NWP's proposed restrictions, the DSIs allege, would not preclude nonfirm energy purchasers from using the PNW Standard rate to "back up" their own resources as part of a PSW surplus firm sale exceeding a 1-month duration. Schoenbeck, DSI, E-DS-04R, 7.

Moreover, as the DSIs argue, dual Standard rates would "for the first time" discriminate between the PSW and PNW regions on the basis of price. Id., 5. CEC concurs. Chamberlain et al., CEC, E-CC-02, 26. The CEC elaborates that dual Standard rates result in two rates for the same product. Id. The regional discrimination resulting from the dual rates, CEC concludes, is unjustified. Id.

Insofar as it appears that NWP's goal for proposing dual Standard rates is aimed at retaining benefits for PNW nonfirm energy purchasers, this can be accomplished with a rate structure that applies to customers in both regions. In response to concerns raised by both PNW and PSW parties, BPA has limited the upward flexibility to 120 percent of BPA's cost of nonfirm energy. Reducing the degree of upward flexibility and removing PSW costs from the upper limit constrains the NF rate to a level that ensures benefits to both PNW and PSW purchasers. Furthermore, the level of the NF Standard rate offered will continue to take into account the markets for nonfirm energy. Within this proceeding, all of the testimony discussing implementing the NF Standard rate has focused on situations of a large supply of nonfirm energy. In this situation, where the Northwest market could not absorb all available nonfirm energy, it is prudent to target the level of the NF Standard rate to the PSW. Unfortunately, based on this discussion, Northwest nonfirm energy customers appear to conclude that PSW decremental costs will always drive the level of the NF Standard rate. This is not true. Under conditions where BPA is unable to market nonfirm energy to PSW utilities, the level of the NF Standard rate will be based on whatever market is available, which most likely will be the PNW.

Decision

BPA adopts a single Standard rate set to clear the available markets. A dual Standard rate could promote inefficient use of resources and erode BPA's revenues from nonfirm sales.

Issue 2

Do BPA's proposed nonfirm energy rates violate regional preference?

Evaluation of Positions

Market expansion rates were included in BPA's initial proposal to enable BPA to reach additional markets when the Standard rate market is exhausted and additional nonfirm energy is still available. BPA, E-BPA-06, 59; Metcalf/Griffin, BPA, E-BPA-24, 7. In order to reach additional markets and not just reduce the prevailing Standard rate market, BPA proposed that all purchasers under the Market Expansion rate be subject to resource economic qualifications and displacement criteria. Id.

PSP&L, MPC, and WWP (Northwest purchasers), argue that the Regional Preference Act was enacted to provide PNW customers assurance that the lowest established rate for sales of energy outside the region is available to PNW customers. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 10. In addition,

these parties argue that the upwardly flexible NF-87 rates do not adequately safeguard regional preference, since the rate could be set at levels that are economic to California but uneconomic to the Northwest. Lauckhart, PSP&L et al., E-PS/MP/WP-01, 5; Exceptions, PSP&L, R-PS/MP/WP-01, 17.

NWP objects to the end-use and shutdown criteria of the Market Expansion rates. Brattebo et al., NWP, E-NP-03, 7. NWP argues that BPA is not authorized to attach additional terms and conditions to a Northwest customer's right to preference delivery of energy, as long as it is willing to take the energy at the established rate. Brattebo et al., NWP, E-NP-03, 7-8. PP&L and PGE agree. Initial Brief, PP&L/PGE, B-PL/GE-01, 52.

The DSIs and SCE argue that preference governs the allocation of BPA's economy energy, not price. Schoenbeck, DSI, E-DS-04R, 14; SCE, WP-87-7229, 4-5. The DSIs urge BPA to retain its past policy of selling economy energy on the same terms and conditions inside and outside the Northwest. Id., 14.

Northwest purchasers and NWP make essentially three different arguments respecting regional preference. The first is that regional preference requires that BPA offer energy to regional customers at the lowest rate before offering it outside the region. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 10; Exceptions, PSP&L et al., R-PS/MP/WP-01, 18; Initial Brief, PP&L/PGE, B-PL/GE-01, 52. The second is that an upwardly flexible rate permits California utilities to effectively "outbid" Northwest utilities for the power--thus denying Northwest utilities the opportunity to exercise their preference rights. Brattebo et al., NWP, E-NP-03, 7.

These two arguments are untenable. Both rely on an assumption that the Regional Preference Act reserves the lowest prices for Northwest customers. As the DSIs and SCE correctly argue, however, preference means that Northwest customers receive a preference to the allocation of power, not to a preferential price. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1125 (9th Cir. 1984); U.S. Department of Energy, Western Area Power Administration, 25 FERC 61,324 at 61,732 (1983). In essence, preference gives Northwest customers a right of first refusal before the energy can be sold outside the region.

The third argument, that BPA cannot require Northwest purchasers to buy energy with the same terms and conditions as applicable to Southwest purchasers, is also untenable. Apparently relying only on the Regional Preference Act and assuming incorrectly that the Act is the source of BPA's ratemaking authority, PP&L and PGE argue that Bonneville is not authorized to condition the right to receive energy at such established rate on the utility's shutdown of a generating plant. Initial Brief, PP&L/PGE, B-PL/GE-01, 51. It is incorrect that BPA is not "authorized" to establish terms and conditions for the sale of energy. BPA is expressly authorized by section 7(a) of the Northwest Power Act, 16 U.S.C. §839e(a), to establish rates which recover costs in accordance with sound business principles. BPA is authorized to attach any terms and conditions to a rate or rate schedule that promote the ratemaking standards expressed in these statutes: ensuring cost-recovery, promoting the widespread use of BPA power, and protecting the interests of the United States in recovering its investment. There is no

conflict between these statutory ratemaking requirements and the Regional Preference Act because the Preference Act contains no standards applicable to BPA's authority to establish rates. U.S. Department of Energy, Bonneville Power Administration, 36 FERC at 65,168, citing U.S. Department of Energy, Bonneville Power Administration, 29 FERC at 65,077.

PP&L and PGE, however, argue that BPA should replace the shutdown criteria with the requirement that Northwest purchasers pay BPA the highest rate when they are making simultaneous sales over the Southern Intertie. Initial Brief, PP&L/PGE, B-PL/GE-01, 51-52. These utilities argue that this requirement is "less objectionable" than BPA's uniform shutdown rule. Id. In essence, NWP urges one set of terms and conditions for California utilities, and another for Northwest utilities. BPA will not adopt special rules for discrete customer classes. These schedules must apply equally to all customers who purchase under them--whether in the Northwest or in the Southwest.

End-use criteria and shutdown rules applicable to both Northwest and Southwest purchasers are essential to the objectives of the Market Expansion rate. The Market Expansion rate serves to increase the size of the market beyond that which is economic at the Standard rate, not to replace sales at the Standard rate with sales at a lower rate which will have a detrimental effect on BPA's revenues. Griffin, BPA, TR 2381. Absent any displacement requirements, concurrent nonfirm energy offers at the Market Expansion rate and the Standard rate could not be sustained. Griffin/Metcalf, BPA, E-BPA-58, 9. The lower Market Expansion rate would erode the higher Standard rate sales. In other words, as the DSIs note, without displacement and eligibility criteria, BPA lacks any ability to determine whether a Market expansion rate will reach markets not economic at the Standard rate, or whether it will merely displace resources which could have been economically displaced at the Standard rate. Schoenbeck, DSI, E-DSI-04R, 10. In any event, the natural result of failure to adopt end-use criteria is that BPA's revenues would be reduced.

The DSIs add that the absence of eligibility requirements in the past exposed BPA to manipulation by utilities who knew BPA could not hold energy indefinitely and would wait until BPA dropped its price before purchasing. Schoenbeck, DSI, E-DS-04R, 11. While NWP asserts that no rate design can totally prevent the "waiting game," the DSIs counter that the eligibility requirements remove the incentive. Id. As the DSIs note, "a utility with a 30 mill resource has every reason to displace that resource with standard rate energy, if the utility knows that no amount of waiting will qualify the resource for displacement with 12 mill power." Id., 11-12.

End-use criteria and shutdown rules are reasonable terms and conditions of rates that permit BPA to meet its statutory ratemaking requirements. Regional preference is not violated when these rules are fairly applied to both Northwest and Southwest purchasers.

Decision

BPA's nonfirm rates do not violate regional preference. Attaching displacement criteria to Market Expansion rates is lawful and appropriate.

Issue 3

Should the NF rate schedule allow offering multiple Market Expansion rates simultaneously?

Evaluation of Positions

BPA proposed to offer more than one Market Expansion rate to increase the nonfirm energy market if additional nonfirm energy is available after the NF Standard rate market has been saturated. Metcalf/Griffin, BPA, E-BPA-24. 11. The Market Expansion rate is lower than the NF Standard rate. BPA, E-BPA-06, 84. Purchases under the Market Expansion rate are subject to displacement eligibility and shutdown criteria. Id.

NWP proposes that BPA offer only one Market Expansion rate, set at a level which maximizes revenues, without attaching displacement criteria or other requirements. Brattebo et al., NWP, E-NP-03, 6. The Market Expansion rate, under NWP's rate proposal, would be a flexible rate between the cost of nonfirm energy and 7.0 mills per kilowatthour. NWP's Market Expansion rate is conceptually similar to BPA's Standard rate.

NWP's assertions that offering only one Market Expansion rate will increase BPA's revenue from below-cost sales are unsupported. In fact, the evidence on the record supports just the opposite. A single Market Expansion rate will erode BPA's revenues. Griffin/Metcalf, BPA, E-BPA-58, 9. As the DSIs correctly argue, NWP's Market Expansion rate would force BPA to offer all market expansion energy at one price set low enough to reach the lowest cost resource BPA seeks to displace. Schoenbeck, DSI, E-DS-04R, 6.

NWP's motivation behind proposing a single rate appears to be a concern not for BPA's revenues but for the prices other sellers can obtain for their nonfirm energy. "When BPA offers several Market Expansion rates BPA drives down the price that both BPA and other Northwest Parties can receive for nonfirm energy." Exceptions, NWP, R-NP-01, 13. NWP arguments that offering only one revenue maximizing Market Expansion rate will increase BPA's revenues are not compelling.

Decision

BPA will maintain its ability to offer more than one Market Expansion rate simultaneously.

Issue 4

Should BPA adopt fixed displacement rates?

Evaluation of Positions

BPA views flexible Market expansion rates as an improvement over specific fixed displacement rates given future fuel price uncertainty. Metcalf/Griffin, BPA, E-BPA-24, 12.

NWP proposes that resource displacement criteria should apply only to low-cost thermal generation. Brattebo et al., NWP, E-NP-03, 8. A rate of 7.0 mills/kWh is proposed for coal plant displacement and 3.0 mills/kWh for nuclear displacement. Id., 9.

NWP did not provide any evidence why a fixed displacement rate is preferable to BPA's proposed Market Expansion rate. Clearly, establishing a fixed rate entails some risk given fuel price uncertainty. In addition, the level of the fixed rates may be lower than the level necessary to achieve BPA's resource displacement objectives and may serve to reduce BPA's revenues. Griffin/Metcalf, BPA, E-BPA-58, 10. Furthermore, if the levels proposed by NWP are necessary to sell all available nonfirm energy, BPA could offer those levels under its flexible rate. Id., 10.

Absent any clear showing of advantages presented by a fixed displacement rate, BPA will retain a flexible rate. A flexible rate imposes less risks and provides clear advantages over fixed displacement rates.

Decision

BPA will not adopt fixed Displacement rates.

Issue 5

Should the Intertie Adder apply to below-cost sales?

Evaluation of Positions

Initially, BPA proposed to apply the Intertie Adder to all nonfirm energy sales made over the Southern Intertie. Metcalf/Griffin, BPA, E-BPA-24, 7. Subsequently, BPA eliminated the Intertie Adder on sales made below cost in order to increase BPA' ability to recover the cost of providing nonfirm energy. Griffin/Metcalf, BPA, E-BPA-58, 11.

PP&L and other generating utilities object to removing the Intertie Adder from below-cost sales over the Southern Intertie. Oral Argument, PP&L, TR 3096. In previous rate cases, PP&L notes, it was established that the users of the Intertie would pay for the Intertie costs through a transmission adder on PSW sales. Id. Removing the Intertie Adder from below-cost sales, PP&L argues, means one of two things: either BPA is not collecting any transmission costs from the PSW or, if the transmission charge is rolled into

the rate, the PSW is paying less for nonfirm energy than customers who do not use the Intertie. Id.; Exceptions, PP&L, R-PL-01, 14. NWP and other purchasers of nonfirm energy agree. Exceptions, NWP, R-NP-01, 14; Exceptions, PSP&L et al., R-PS/MP/WP-01, 17.

Prior to the 1985 rate case, BPA designed and offered its nonfirm energy rates without regard to the Intertie Adder, such that rates to both regions were the same. See 1983 ROD, WP-83-A-BPA-02, 295-b. Beginning in 1985, however, the vast majority of PSW sales were forecast at the Standard rate. For sales made at or above the total cost of nonfirm energy, it is appropriate to reflect the cost difference between the two regions caused by the PSW use of the Southern Intertie. Griffin/Metcalf, BPA, E-BPA-58, 16. This is not the case when BPA is unable to collect the full cost of providing service. In this case the issue of recovering the full amount of any particular cost item--including the Intertie Adder--becomes meaningless. When PSW sales are made at rates less than or equal to the cost of nonfirm energy (not including Intertie costs), there is no cost basis for reducing PNW prices even further. Id., 11. In fact, under these circumstances, steps taken to minimize revenue losses experienced from below-cost sales are prudent. Steps to reduce, in total, the underrecoveries experienced because of below-cost sales in turn reduce the amount of revenues BPA must recover when sales can be made above cost in order to meet its cost recovery objective. This serves to enhance BPA's ability to recover on average its costs or at least reduces the variance between costs and actual revenues received. In turn, all of BPA's customers stand to benefit. This same rationale also applies to below-cost sales under the SP-87 rate schedule. Removing the Intertie charge from below cost sales made under the SP-87 rate schedule furthers BPA's objective to minimize underrecoveries from below cost sales. The same arguments for eliminating the Intertie charge from below-cost nonfirm sales apply to below cost surplus firm power sales.

PP&L, joined by other Northwest purchasers, asserts that eliminating the Intertie Adder discriminates against regional customers. Exceptions, PP&L, R-PL-01, 14; Exceptions, PSP&L et al., R-PS/MP/WP-01, 17. The perception of these customers is that this action further erodes regional preference or at least provides an economic incentive for BPA to violate regional preference. BPA has determined that the NF rate does not violate regional preference. See Issue B.2.2. PSP&L, MPC, and WWP's argument that regional preference is violated because eliminating the Intertie Adder gives PSW purchasers a price advantage over PNW purchasers is not convincing. Exceptions, PSP&L et al., R-PS/MP/WP-01, 17. When BPA is offering exactly the same nonfirm energy price to both regions, neither region has a clear price advantage over the other.

Decision

When selling below cost to the PSW, BPA will offer nonfirm energy to the PNW at the same rate as to the PSW, not at a rate lowered by the Intertie Adder.

Issue 6

Should BPA require displacement of coal-fired generation prior to offering a Market Expansion rate to gas end-users?

Evaluation of Positions

BPA proposes that a Market Expansion rate be available to any purchaser that has a qualifying unit with decremental cost that would not allow the unit to be economically displaced at the Standard NF rate being offered. BPA, E-BPA-06, 79 amd B53-B54.

WUTC objects to displacement of some natural gas end-uses with the Market Expansion rate prior to the displacement of all coal-fired generation. Lazar, WUTC, E-WU-01, 4; Exceptions, WUTC, B-WU-02, 4. Currently, WUTC contends, natural gas is a more economic way to produce energy than is coal-fired generation. Lazar, WUTC, E-WU-01, 7. WUTC urges BPA to take a regional perspective on the economics of gas displacement. Exceptions, WUTC, B-WU-02, 4. Towards this end, WUTC recommends that BPA adopt a policy to displace coal generation prior to displacement of gas end-use. Id.

WUTC bases its recommendation on its assessment of incremental gas costs compared to incremental coal costs. Lazar, WUTC, E-WU-01, 7. Based on this assessment, WUTC concludes that the incremental cost of gas to the region is lower than the region's incremental cost of operating existing coal plants, even though the total retail cost of gas, including a contribution to fixed costs, may exceed the incremental cost of operating a coal plant. Id. Therefore, WUTC argues, the region as a whole would be worse off if gas end-uses were displaced prior to displacement of the coal-fired generating plants. Id., 8. WUTC recommends that BPA allow natural gas end-use to be displaced only when the Market Expansion rate can be set below the regional system decremental (variable) costs of natural gas. Id., 10; Exceptions, WUTC, B-WU-02, 4.

When below-cost sales are necessary, BPA strives to maximize its revenues in order to meet its obligations to the Treasury. WUTC's proposal would force BPA to set Market Expansion rates below the market-clearing price for such sales, thus reducing revenues for BPA and jeopardizing its Treasury payments. This might happen by precluding potential sales that could be made to natural gas end-users who may be willing to purchase under a Market Expansion rate that was above the clearing rate for displacing coal-fired generation.

Decision

BPA will continue its practice of allowing any eligible purchaser to purchase electricity under the NF rates, including the Market Expansion rate. Requiring that all coal-fired generation be displaced before natural gas end-use is displaced may reduce BPA's revenues.

Issue 7

Should BPA use a production simulation model to set the level of the NF Standard rate?

Evaluation of Positions

NWP urges BPA to use a production cost simulation model to estimate PNW and PSW decremental costs for purposes of setting nonfirm energy rates. Brattebo et al., NWP, E-NP-03, 3-4. NWP argues using a model will provide BPA with an objective basis for determining the particular rate level for the NF Standard rate instead of relying on the best judgment of its schedulers to determine decremental cost. Initial Brief, NWP, B-NP-01, 6.

While BPA does not disagree that a production cost model may be a useful tool to enhance BPA's marketing efforts, clearly it is not a substitute for BPA's schedulers' experience and assessment of actual hourly conditions in the nonfirm energy markets. Most of the cost data NWP proposes to use in determining California decremental cost are based on historical information. Initial Brief, NWP, B-NP-01, 7. Realtime assessment of current market conditions, including resource and transmission limitations, will continue to be an important factor in setting BPA's nonfirm energy prices. Griffin/Metcalf, BPA, E-BPA-58, 12. In the course of determining prices for nonfirm energy, BPA examines the actual pattern of Southern Intertie use to determine which PSW utilities are capable of purchasing BPA nonfirm energy. Id. In addition, some market information such as other economy energy transactions and California utility loads and operations are generally not available except after the fact. Id.

In fact, as NWP acknowledges, BPA schedulers have been successful in establishing an NF Standard rate which reflects market conditions. Initial Brief, NWP, B-NP-01, 7. The average nonfirm energy revenues received from SCE (NWP's example utility) in 1986 were actually slightly higher than the rates that would have resulted if BPA has used the rate proposed by NWP in conjunction with the proposed model. Griffin/Metcalf, BPA, E-BPA-58, 13. NWP suggests that changing regulations and corresponding changes in market conditions will lessen BPA's future ability to set nonfirm energy rate levels based on decremental cost conditions in California. Initial Brief, NWP, B-NP-01, 7. It is precisely for this reason that BPA is unwilling to rely solely on a model for setting its nonfirm energy rates. In a period of rapid change and uncertainty the usefulness of a model, using historical cost data, is reduced.

NWP further suggests analysis using a production simulation model will assist BPA in developing and evaluating power marketing strategies. Peters/Branchcomb, NWP, E-NP-02, 22. NWP offered a number of useful observations on the California market which were supported by their modeling efforts. First, NWP noted that gas-fired generation continues to be the marginal resource most of the time (86.5 percent of the time) but coal is also a displaceable resource for BPA's nonfirm energy (13.5 percent of the time) on SCE's system. Id., 23. Furthermore, NWP's analysis suggests the value of BPA's nonfirm energy varies by time of day which justifies time of day pricing

for nonfirm energy. Id., 12. BPA appreciates NWP's efforts to undertake this analysis and present this information for consideration. NWP's analysis validates BPA operating procedures currently in place. BPA has in the past offered nonfirm rates whose level varies for peak and offpeak hours. Griffin/Metcalf, BPA, E-BPA-58, 14. BPA will continue this practice in the future if the situation warrants. BPA acknowledges NWP's reminder that gas pricing in California will continue to be an important factor in BPA's nonfirm energy and surplus firm power marketing strategy. Branchcomb/Peters, NWP, E-NP-02, 24. BPA has and will continue to closely follow regulatory pricing actions which will impact BPA's PSW economy energy market. In addition, BPA will continue its efforts to monitor utility system loads, hydro conditions, and forced or scheduled outages of major baseload facilities and other events which affect the California power market. Griffin/Metcalf, BPA, E-BPA-58, 14.

Decision

BPA will continue to set its nonfirm energy rates based on the best data available and the informed judgment of its schedulers. Rates for hourly sales of nonfirm energy are best determined based on actual market conditions.

3. Share-the-Savings Rate

Issue 1

Should BPA adopt an experimental share-the-savings rate for the two-year rate period?

Evaluation of Positions

BPA proposed an experimental share-the-savings (SS-87) rate in its initial proposal. BPA, E-BPA-06, 81-82. Share-the-savings rates have merit; however, these rates are complex administratively and thus present implementation problems which have not been fully resolved. Metcalf/Griffin, BPA, E-BPA-24, 18-19. BPA's rationale for proposing an experimental SS-87 rate was to enable BPA to gain experience in transacting sales under this type of rate design without jeopardizing BPA's ability to market nonfirm energy if such a rate proves unworkable. Id., 19.

NWP concludes that an additional experimental SS-87 rate is unnecessary. Upward flexibility in the NF-87 rate tied to purchasing utilities' decremental cost achieves the same objectives as a share-the-savings rate. Opatrny/Peters, NWP, E-NP-01, 5; Initial Brief, NWP, E-NP-01, 2.

The DSIs suggest that the SS-87 rate is unrealistic. Schoenbeck, DSI, E-DS-04R, 13. Instead, they urge BPA to adopt only one economy energy rate schedule, NF-87, which prices all energy at a fixed percentage of a purchaser's decremental cost. Id.

SCE reiterates past California arguments that BPA's nonfirm energy must be based on cost. A share-the-savings rate, SCE asserts, is inconsistent with BPA's statutory requirements. SCE, WP-87-7229, 25-27. PG&E, however,

expresses interest in a share-the-savings rate, although not BPA's SS-87 rate. PG&E, WP-87-7749, 2. PG&E supports a split-the-savings rate in order to assure a fair sharing of benefits between the two regions. Id.

BPA is not willing to abandon experimental share-the-savings rates at this time for two reasons. First, it appears that many of BPA's customers support these rates, or support rates that embody share-the-savings concepts. While NWP asserts that the SS-87 rate is unnecessary, the rate proposed by NWP is based on a share-the-savings concept. NWP's proposed rate is a market-based rate tied to a purchaser's decremental cost. Brattebo et al., NWP, E-NP-03, 2. (NWP's proposed rate for nonfirm energy transactions is discussed more fully in section B, 2.) Clearly support for a share-the-savings rate exists in the Northwest. See also, 1985 Rates ROD, WP-85-A-02, 270.

In addition, it appears that BPA's Southwest customers may now be willing to publicly support share-the-savings rates. PG&E supports a share-the-savings rate based on a 50-50 split of the seller's incremental costs and the buyer's decremental costs. PG&E, WP-87-7494, 2. Comments of other California utilities--including SCE--and California regulators during a recent Congressional oversight hearing on the Intertie Access Policy suggest that California regulators and other utilities in the PSW are interested in considering share-the-savings rates.

Second, share-the-savings rates have merit. Share-the-savings rates provide rate predictability because they ensure that purchasers and sellers will benefit from nonfirm energy purchases. Metcalf/Griffin, BPA, E-BPA-24, 28. Furthermore, share-the-savings pricing mechanisms are a standard industry practice for marketing economy energy. Id., 18. A share-the-savings rate may also result in greater sales compared to BPA's cost-based rate. Griffin, BPA, TR 2386.

In designing the SS-87 rate, BPA attempted to improve on the SS-85 rate. Metcalf, BPA, TR 2388. Specifically, BPA attempted to eliminate some of the impediments which may have contributed to a purchaser electing to forgo purchasing under this type of rate. Metcalf/Griffin, BPA, E-BPA-24, 20. Nevertheless, the DSIs and PG&E suggest that the proposed SS-87 rate may not be viable for conducting an experimental rate transaction. Schoenbeck, DSI, E-DS-04R, 13; PG&E, WP-87-7494, 4-5.

BPA agrees with these comments. BPA's SS-87 rate is not tailored to individual customers, but was designed to facilitate recovery of BPA's costs. As such, there may be particular circumstances applicable to an individual utility where purchases at the offered SS-87 rate may not be economic. In addition, BPA's SS-87 rate may be too highly structured to permit negotiation of SS-87 contracts. Unforeseen problems presented by the proposed SS-87 rate that are incapable of resolution because of the highly structured nature of the SS-87 rate may be identified during negotiation.

Under these circumstances, it is prudent to maintain a share-the-savings rate. However, it may not be prudent to retain the constricting structure of the proposed SS-87 rate. BPA believes that a share-the-savings experiment would have a better chance of success if the SS-87 rate were not structured,

but rather allowed a formula to be negotiated between BPA and the buyer subject to a floor and a ceiling set by the NF rate cap.

Decision

BPA proposes an experimental share-the-savings rate to enable BPA to gain experience transacting nonfirm energy sales under these rates. To increase the chances that such an experiment will be successful, the SS-87 rate will permit the rate formula to be negotiated between the buyer and seller subject to a floor and the NF rate cap.

4. Energy Broker Rate (EB-87)

Should BPA adopt the EB-87 rate?

Evaluation of Positions

Initially BPA proposed including the Energy Broker rate (EB-87) as part of its 1987 wholesale rates. None of the parties or participants raised any issue pertaining to or provided any comments on the EB-87 rate. An Energy Broker rate was first included in BPA's 1982 rates and was available for nonfirm energy sales among participants to the Western Systems Coordinating Council (WSCC) Energy Broker System. Although the Energy Broker System was disbanded in September 1984, BPA retained the EB rate as part of its 1985 wholesale rates because there was uncertainty whether the participants would agree to reinstate another similar bulk power marketing arrangement.

Many of the participants to the WSCC Energy Broker Agreement are now participating in the newly created Western Systems Power Pool (WSPP) experiment. Instead of creating a separate wholesale rate schedule for transactions under the WSPP Agreement, BPA made the NF-87 and SP-87 rates available for these sales. Since BPA's initial proposal, the WSPP Agreement was approved by the FERC, and transactions under this agreement have commenced. Pacific Gas & Electric Co., FERC ¶61,242 (1987). There is no reason to believe the EB-87 rate will be needed during this rate period.

Decision

BPA does not adopt the EB-87 rate schedule.

C. Nonfirm Energy Rate Cap

Issue 1

Should BPA adopt a nonfirm energy rate cap?

Evaluation of Positions

BPA proposed to adopt a cap applicable to all sales of nonfirm energy for 12 years. Melton/Margeson, BPA, E-BPA-25, 5. BPA intended that the cap would

be used by regulators in California as a tool to enable them to compare the economics of relying on BPA nonfirm energy in their resource planning to the economics of developing alternative generation in California. Id., 9.

CEC supports adoption of a cap, arguing that this will preserve BPA's market for nonfirm energy in California over the long term. Chamberlain et al., CEC, E-CC-01, 8.

NWP, DSIs, and WPAG oppose any cap. These parties argue that there has been no demonstration that the cap will benefit BPA or its other customers by preserving BPA's nonfirm energy markets. Opatrny/Peters, NWP, E-NP-01, 5; Schoenbeck, DSI, E-DS-04R, 2; McGary et al., WPAG, E-WA-01, 6-7.

CEC first suggested that BPA develop a long-term rate cap or formula applicable to nonfirm energy rates in BPA's 1985 rate case. Chamberlain et al., CEC, E-CC-01, 8. In that proceeding, CEC argued that California utilities and regulators need long-term rate predictability in order to assure benefits from future investment in the Southern Intertie. 1985 Rates ROD, WP-85-A-02, 327. Although BPA did not adopt a rate cap in that proceeding, the Administrator agreed to explore the possibility of establishing a long-term methodology to provide California some rate stability. Id., 328.

BPA, CEC, and CPUC began exploration of nonfirm energy predictability issues in the fall of 1985. During those discussions, BPA agreed to prepare a joint issue paper with CEC and CPUC. BPA expected that the joint paper would clarify issues and lead to a better understanding of the relationship between California regulatory decisions and BPA's nonfirm energy rates. BPA, E-BPA-06, 60.

In ensuing discussions on the issue paper, California regulators argued, as CEC argues now, that BPA has the inclination to market its nonfirm energy to California such that BPA's prices will fall only a mill or two below California's decremental costs. Chamberlain et al., CEC, E-CC-1, 9, 11. If gas and oil prices rise to levels experienced in the early 1980s, California regulators fear that BPA's prices would rise very high. CEC also argues that other suppliers, particularly PURPA qualifying facilities (QFs), could potentially supply all of California's future resource needs. Id., 15; Chamberlain et al., CEC, E-CC-02, 4-7; Initial Brief, CEC, B-CC-01, 21. Future regulatory decisions would choose between QF generation and alternatives, including BPA economy energy, to meet those future requirements. These decisions would depend, CEC asserts, in large part on California regulators' expectations of how BPA would price nonfirm energy in the future. Chamberlain et al., CEC, E-CC-03, 2; Initial Brief, CEC, B-CC-01, 18. If there was no long-term assurance that BPA would not price its nonfirm energy below California decremental cost by 1 or 2 mills, CEC concludes, then California regulators' decisions would probably encourage development of within region resources. Chamberlain et al., CEC, E-CC-01, 12; E-CC-03, 2; Initial Brief, CEC, E-CC-01, 21-22.

BPA disagreed then and continues to disagree with California regulators that BPA's rates disadvantage California or that BPA intends to follow

California decremental costs by one or two mills as gas and oil prices rise. Melton et al., BPA, E-BPA-59, 11. Nevertheless, BPA concluded that perceptions of California regulators would drive their decisions, and that, ultimately, BPA's markets in the PSW could be affected by these decisions. Melton/Margeson, BPA, E-BPA-25, 3. In particular, BPA agrees with CEC that California regulators' siting decisions for alternative generation, primarily QFs, and long-term avoided cost determinations could have a substantial impact on future BPA markets for nonfirm energy. Id., 3. See also Chamberlain et al., CEC, E-CC-01, 15.

BPA proposed a long-term rate cap in this proceeding to address the specific CEC and CPUC concern that BPA's nonfirm energy prices would track California decremental costs by one or two mills as these costs rise well above BPA's cost. Melton/Margeson, BPA, E-BPA-25, 3. Specifically, California regulators were concerned that if gas and oil prices were to return to the levels of the early 1980s, BPA would continue to price nonfirm energy only slightly below California's instantaneous alternative cost. Chamberlain et al., CEC, E-CC-01, 9. In effect, the cap was designed as a regulatory tool to enable California regulators to evaluate BPA's nonfirm energy against their alternatives and make the best economic decisions--retaining a place in California's resource mix for BPA's nonfirm energy. Melton/Margeson, BPA, E-BPA-25, 11.

Many of BPA's Northwest customers object to any long-term mechanism which reduces BPA's future pricing flexibility. NWP, WPAG, and the DSIs question whether the proposed NF rate cap will actually secure a portion of the future PSW economy energy market for BPA's nonfirm energy. Opatrny/Peters, NWP, E-NP-01, 7; Initial Brief, NWP, B-NP-01, 11-12; Exceptions, NWP, R-NP-01. 8; McGary et al., WPAG, E-WA-01, 8; Schoenbeck, DSI, E-DS-04R, 2. WPAG and NWP note that BPA is proposing to unilaterally limit its NF rate without any compensating reciprocal action from California regulators or utilities. McGary et al., WPAG, E-WA-01 7; Opatrny/Peters, NWP, E-NP-01, 6. NWP urges BPA not to adopt the rate cap because there has been no demonstration of any benefits of this proposal. Peters/Opatrny, NWP, E-NP-01, 7; Initial Brief, NWP, B-NP-01, 11; Exceptions, NWP, B-NP-01, 12. NWP argues that it is impossible to determine "how many QFs will or will not be sited and actually operated during the next 12 years, either with or without the price range of the proposed NF rate cap." Initial Brief, NWP, B-NP-01, 10. Absent any compensating action from CEC or CPUC, NWP and WPAG conclude there is no evidence to suggest that the proposed rate cap "will enable BPA to sell one single kilowatthour more of power or earn one extra mill in revenues." Id., 11; Exceptions, NWP, B-NP-01, 12.

CEC disagrees with NWP and argues that California regulators have already acted to reduce potential erosion of Northwest nonfirm energy markets in California. Chamberlain et al., CEC, E-CC-01, 16-19; E-CC-02, 14. These actions, CEC asserts, have already benefited BPA. Exceptions, CEC, R-CC-01, 11. As part of the Sixth Electricity Report (ER-6), CEC notes that the Commissioners took two specific actions designed to protect PNW markets in California for nonfirm energy. Chamberlain et al., CEC, E-CC-01, 17; E-CC-02, 14. The Commissioners undertook these actions based on BPA's

statements in ER-6 that a rate cap would be proposed and considered in the 1987 rate proposal. Id., 20; Initial Brief, CEC, B-CC-01, 24.

First, 13,150 gWh of Northwest nonfirm energy backed up by existing gas and oil units were classified as a core resource in ER-6. Chamberlain et al., CEC, E-CC-01, 19. CEC defines core resources as "resources that for economic or contractual reason, or for physical reasons relating to public health and safety or environmental quality, cannot or should not be displaceable." Id. This action, CEC asserts, has already preserved flexibility in California's generation system necessary to ensure that new facilities will not preclude California utilities from taking advantage of nonfirm energy. Id.

Second, CEC argues ER-6 has more stringent licensing requirements for new in-state thermal power generation facilities. Every proposed new facility is required by CEC to either meet both a physical and economic needs test, or alternatively to meet a balancing test. Id., 18. The balancing test requires the proponent to show that the facility would be beneficial to California even if it does not meet the physical and economic needs tests. Id., 18-19. CEC further observes that representatives of the QF industry have stated that these newer policies have had a substantial chilling effect on QF development and financing, even before the policies have been applied in CEC licensing proceedings. Chamberlain et al., CEC, E-CC-02, 14, footnote 8; Initial Brief, CEC, B-CC-01, 24.

NWP questions the need for a rate cap given the uncertainty of whether future QFs will be dispatchable. Opatrny/Peters, NWP, E-NP-01, 12. Statements by California utilities, NWP asserts, indicate that PSW utilities favor QF dispatchability based on expectations that future Northwest nonfirm energy would be priced economically. Id. NWP apparently believes it is only a matter of time before the California regulators also realize the benefits of QF dispatchability. Id., 13. NWP implies that QF dispatchability will occur absent any rate cap simply because that is the more economic decision, and concludes that with dispatchability requirements BPA's market for nonfirm energy in California will not be diminished even if more QFs are sited. Id.

CEC argues that NWP unrealistically assumes that QF dispatchability will occur. While PSW utilities prefer QF dispatchability, CEC notes that the CPUC has not required dispatchability in Standard Offers to date, even though PSW utilities have urged that displacement provisions be included. Chamberlain et al., CEC, E-CC-02, 8. Clearly, the more price assurance California regulators have with respect to BPA nonfirm energy, the greater the incentive to require QF dispatchability.

No witness in this proceeding disagrees with NWP's observation that the impact of the rate cap on future QF development in California is uncertain. NWP is correct that there has been no conclusive demonstration that the rate cap will provide an absolute benefit to BPA in the form of retaining its nonfirm energy markets. See Opatrny/Peters, NWP, E-NP-01, 12, Chamberlain et al., CEC, E-CC-02, 6-7; McGary et al., WPAG, E-WA-01, 7-8; Exceptions, NWP, R-NP-01, 8. Neither has there been a conclusive demonstration in this case that BPA will be harmed by adopting a rate cap even if the cap fails to influence PSW QF development. Although NWP suggests that the rate cap might

be detrimental to BPA because it would preclude cost recovery over time, no party provided verifiable evidence that the rate cap would impede cost recovery. See Opatrny/Peters, NWP, E-NP-01, 6 and 8; Exceptions, NWP, R-NP-01, 7.

The record does support the conclusion that the rate cap will not be detrimental to BPA. Although issues respecting the design of the rate cap are discussed in more detail below, the cap was designed so that it would be compatible both with cost recovery and future designs of nonfirm energy rates. BPA's testimony demonstrates that the cap will allow BPA to recover its costs if BPA continues to utilize cost-based nonfirm energy rates. Melton, BPA, E-BPA-59, Attachments 1 and 2. For this rate period the cap is outside of the range of prices BPA can offer under the NF-87 Standard rate. BPA's upper limit for the NF Standard rate is set below the minimum level established for the cap. See Section B.1., Issue 3. Contrary to NWP's assertions that the rate will limit BPA's ability to participate in FERC endorsed free market transactions, BPA's testimony also demonstrates that adoption of a share-the-savings rate, an often used rate for economy energy transactions, would not be precluded by the cap. Id.

There is sufficient evidence that BPA may benefit from adopting the cap. Since enactment of PURPA in 1978, independent generating facilities or QFs have rapidly become the major source of new electricity supplied in California. The pace of QF growth has been dramatic. In 1984, QFs were supplying 1,500 MW of capacity and energy to California's energy supply. By the end of 1986, QF electricity supply doubled to over 3,700 MW of capacity and energy. 1986 Electricity Report (ER-VI), Chapter 3, pg. 4. Although the exact amount of future electricity expected to be supplied by QFs in California has been debated, most parties acknowledge the potential for QF development. Even NWP's conservative calculation of likely QF generation--6,785 aMW or close to 60,000 gWh--poses a serious constraint on PSW utilities' ability to accept economy energy available from the PNW. See Opatrny/Peters, NWP, E-NP-01, 11; Chamberlain et al., CEC, E-CC-02, 4-5; Initial Brief, CEC, B-CC-01; 11; PG&E, WP-87-7494, 3.

Moreover, there is no reason to believe this potential generation will necessarily be physically displaceable by economy energy purchases in the future, despite the apparent benefit of making all resources as dispatchable as possible. In addition, dispatchability may mean that a QF merely accepts a lower price for deliveries during offpeak or super offpeak periods rather than physical displacement. This potential generation could exacerbate an existing oversupply problem in California. Current QF generation, coupled with recent large baseload thermal additions in California, has already contributed to an increase in the frequency of minimum generation conditions in California. In the past year, minimum generation conditions existing in California have been one of the reasons PSW utilities have been unable to accept offers of nonfirm energy at any price. Griffin, BPA, TR 222. NWP agrees. Opatrny, NWP, TR 2426. Further increases in must-run or nondispatchable resources can only exacerbate the problems of minimum generation experienced in California, which in turn will be detrimental to BPA and potentially expensive for California ratepayers.

All parties in this case agree that California regulators will act in the best economic interests for California utilities and ratepayers. The source of disagreement between the parties is what constitutes economically rational actions. NWP and WPAG argue actions that foreclose PSW utilities from purchasing nonfirm energy are uneconomic. Opatrny, NWP, TR 2427; McGary et al., WPAG, E-WA-01, 8. Nevertheless, the perception in California is that PNW economy energy will become uneconomic in the future. Chamberlain et al., CEC, E-CC-01, 8; Exceptions, CPUC, R-CP-01, 3. Consequently, California regulators consider QFs a viable long-term economically rational alternative to continued reliance on PNW economy energy.

While BPA believes that the perception of California regulators is unwarranted, these perceptions are currently influencing their decisions. BPA anticipates that the rate cap, rather than California regulators' current perceptions, will define "worst case conditions" for future nonfirm energy prices. In this way the rate cap will allow California regulators to evaluate realistically the economics of BPA nonfirm energy in relation to their alternatives. The rate cap should encourage the CEC to move toward including larger amounts of PNW nonfirm energy in its resource planning so that there will be less room on a planning basis for QF proponents to demonstrate that additional generation is "needed." Chamberlain et al., CEC, E-CC-01, 17-19. This is supported by CEC's testimony in this case that their action in ER-6 may have already slowed development of QF generation in California. Chamberlain et al., CEC, E-CC-02, 14 at footnote 8. Likewise, the CPUC should recognize the competitiveness of BPA economy energy prices in determining avoided cost payments made to QFs.

Decision

BPA will adopt a nonfirm energy rate cap to address concerns expressed by California regulators that BPA's nonfirm energy rate in the future may become uneconomic. The proposed long-term cap imposes little revenue risk on BPA and may secure a place for BPA's economy energy within California electricity supply options.

Issue 2

Should the nonfirm energy rate cap be implemented through contracts with BPA's customers?

Evaluation of Positions

BPA proposed to adopt a long-term cap for its nonfirm energy rates to address California regulators' perceptions that the only restriction on the level of BPA's nonfirm energy rates is California's decremental cost. Even though BPA's nonfirm energy rate would always be below California decremental costs, from California regulators' perspective, if gas and oil prices returned to early 1980 levels, indigenous resources such as cogeneration facilities may be preferable to economy energy purchases. Melton/Margeson, BPA, E-BPA-25.

BPA proposed to implement the nonfirm energy rate cap unilaterally by adopting the cap in this proceeding and asking FERC for 12-year approval. Melton/Margeson, BPA, E-BPA-25, 6. The rate cap is specifically designed to address California regulators' concerns respecting the relationship between PSW decremental fuel costs and BPA's rates for nonfirm energy if gas and oil prices return to the levels of the early 1980s. Id., 9. BPA expected that by providing California regulators with a tool specifically designed to assure benefits from nonfirm energy purchases if gas and oil prices rise in the future, California regulators would act in the best economic interest of California utilities and their ratepayers by assuring that California utilities continue to have the opportunity to purchase nonfirm energy from BPA. Id., 6. The potential benefits to BPA of the rate cap are therefore predicated on appropriate California regulatory actions.

The CEC has essentially two concerns regarding BPA's initial proposal. First, the CEC has argued that implementing the cap through long-term contracts is an essential element of long-term rate certainty. CEC argues that without any mechanism to remove the threat that the cap could be modified or rescinded by future Administrators, the rate cap would be useless to California regulators because they will not perceive BPA as being committed to keeping the cap in place for any substantial period of time without the contract. Chamberlain et al., CEC, E-CC-01, 26-27; Exceptions, CEC, R-CC-01, 13, 18. CEC urges BPA to offer to include the rate cap in all contracts for the sale of nonfirm energy. Chamberlain et al., CEC, E-CC-01, 39. CEC does not question BPA's current commitment to a 12-year cap. Exceptions, CEC, R-CC-01, 2. Nevertheless, CEC stresses that without a contract, there is no certainty that the cap will survive during the critical years: years 5 through 12. Id., 18.

California regulators' perceptions that BPA would not be committed to the rate cap absent a contract are puzzling. BPA's decision to propose a rate cap was made only after the merits of the cap had been carefully considered for over a year. The cap was proposed following both informal discussions between California regulators and BPA and subsequent discussions with representatives from all of BPA's customer groups. The decision to adopt the rate cap in this proceeding has not been supported by either BPA's Northwest or California customers. BPA is now prepared to file this cap with FERC and undertake the necessary actions to gain its approval for 12 years. Absent clear customer support from California and probable Northwest objection, the task of convincing FERC to approve the cap for 12 years is not one BPA undertakes lightly. BPA believes its decision to propose the cap and its commitment to seek FERC approval demonstrates the agency's commitment to the cap.

CEC expresses a desire for additional certainty regarding future actions BPA Administrators may take respecting BPA's nonfirm energy rates. BPA faces similar uncertainty regarding the actions California regulators may take regarding BPA's resources in the future. Being a regulatory agency, the CEC cannot enter into any agreement which prejudges or binds future decisions. Melton et al., BPA, E-BPA-59, 7; Chamberlain et al., E-CC-01, 26-27; Chamberlain, CEC, TR 2204. Consequently, CEC can not provide BPA any certainty that future Electricity Reports will not reverse decisions made in the Sixth Electricity Report. Id., 2205. There appears to be no reason why a

QF could not forestall filing an application for certification with the CEC until subsequent, and possibly more favorable, Electricity Report assumptions are adopted. As CEC admits, it is uncertain whether the rate cap will have any effect on QF development or citing decisions because of considerations other than the CEC's economic and physical need tests. Id., 2253; Chamberlain, CEC, E-CC-01, 7. Similarly, there is no certainty with respect to future CPUC actions. It is unknown whether future CPUC decisions will adversely impact BPA's PSW market by encouraging QF development through high avoided cost payments. Id., 2206. In addition, there is no guarantee that the California legislature will not take future actions that override both CEC's and CPUC's decisions and prove detrimental to BPA's economy energy market. Id., 2205. In conclusion, both California regulators and BPA face significant uncertainty.

In the Draft ROD, BPA accepted the CEC's representations that a contract implementing the rate cap would be necessary and indicated a willingness to explore implementation of a contract that assures both regions benefit from the cap. Draft ROD, WP-87-A-01, 151. BPA believes the contract should serve to reduce both the uncertainties for California regulators that the rate cap will survive and the uncertainties for BPA that California regulators will make appropriate planning decisions assuring California's ability to take advantage of BPA's nonfirm energy. The contract and consequently contract negotiations should address uncertainties facing both California and BPA. If the uncertainties for California are reduced without a corresponding reduction in the uncertainties for BPA, the cap may not be mutually beneficial. WPAG has provided a reasonable recommendation that the rate cap be expressly linked to favorable regulatory treatment of BPA's surpluses. Exceptions, WPAG, B-WA-02, 27; Melton et al., BPA, E-BPA-59, 8. While this may be one approach to pursue, other avenues that achieve certainty to both regions should also be explored in the negotiations. BPA will not predecide here how these uncertainties should be addressed in the contract.

BPA is still not convinced that California utilities will enter into a contract implementing the rate cap since the cap appeared to be inconsistent with previous litigation positions. CEC, however, appears reasonably confident that California utilities would not be opposed to executing a contract implementing the rate cap in exchange for nominal consideration. Chamberlain et al., CEC, E-CC-03, 7; Exceptions, CEC, R-CC-01, 15-17. If California utilities are unwilling to enter into a reasonable contract to implement the cap, the CEC implies BPA will not be responsible for failure to achieve predictability through this mechanism. Exceptions, CEC, R-CC-01, 16, footnote 6. With that understanding, BPA will proceed with contract negotiations upon FERC's interim approval of the rate cap.

The CEC's second concern is that BPA will require extraordinary consideration from California utilities in exchange for contract modification. CEC apparently seeks a commitment from BPA in this rate case that BPA will seek only nominal consideration from California utilities in exchange for contract modification to include the rate cap. Initial Brief, CEC, B-CC-01, 30-31; Exceptions, CEC, R-CC-01, 12. The issue of consideration is one that is more properly dealt with in contract negotiations--not in this rate case. However, as BPA stated in its testimony, BPA is not looking to

California utilities for any particular action in exchange for the cap, but is specifically looking for appropriate California regulatory decisions. Melton et al., BPA, E-BPA-59, 6. Because BPA is not looking to California utilities for any specific reciprocal action, BPA does not expect that consideration from the utilities will be a large issue in negotiations. Rather, BPA is looking for reciprocal action from the regulators.

Decision

BPA will begin contract negotiations upon interim FERC approval of the rate cap. Contract negotiations will address how the contract can resolve uncertainties for both regions.

Issue 4

How should a rate cap be set?

Evaluation of Positions

The proposed NF rate cap is a formula rate based on the greater of BPA's average system cost (BASC) or BASC plus 30 percent of the difference between BASC and PSW decremental fuel costs. Melton/Margeson, BPA, E-BPA-25, 5. BASC is defined as BPA's total revenue requirement for the test period divided by the total system load expected assuming an average of 40 water years over the same time period. Id., 9.

NWP opposes any long-term caps. A commitment never to charge greater than 75 percent of a purchaser's decremental cost, NWP argues, meets any future predictability needs. Opatrny/Peters, NWP, E-NP-06R, 5.

CEC opposes a cap which includes PSW decremental costs. A long-term cap based solely on BPA's costs, CEC asserts, is more stable and predictable. Chamberlain et al., CEC, E-CC-02, 19-20.

While NWP is opposed to any long-term limits on nonfirm energy pricing flexibility, nevertheless it offered two rate cap alternatives to BPA's proposal during this proceeding. NWP initially argued that the formula proposed by BPA is too restrictive when PSW decremental costs are relatively close to BASC. Opatrny/Peters, NWP, E-NP-01, 8. BPA's cap, NWP asserts, does not allow sufficient flexibility in nonfirm energy pricing to allow cost recovery over time. To overcome the limiting effects of the cap when the two regions' costs are fairly close, NWP suggests ramping in the impacts of the cap as PSW decremental costs increase. Id. The cap formula initially advanced by NWP is similar to that proposed by BPA, except that the percentage applied to the difference between BASC and PSW decremental cost varies based on the relationship between these two costs. Id., 14. NWP proposes a cap equal to the greater of BASC or BASC plus the ratio of BASC to PSW decremental costs applied to the difference between BASC and PSW decremental cost. Id., 15. NWP concludes that its proposed cap allows a greater degree of cost recovery than BPA's cap when PSW decremental costs and BASC are relatively close but allows greater benefits to the purchaser than BPA's rate cap when

decremental costs increase substantially. Id., 8. While the DSIs propose adopting a share-the-savings rate as a method for providing rate predictability, they nevertheless support NWP's proposed rate cap. Schoenbeck, DSI, E-DS-04R, 2.

The benefits NWP ascribes to its rate cap are illusory. The increased pricing flexibility that NWP asserts their proposed rate cap provides when PSW and BPA's costs are fairly close is deceptive and will not result in recovering greater revenues. Melton et al., BPA, E-BPA-59, 2-3. While it is true that NWP's rate cap is higher than BPA's cap when PSW decremental costs are relatively close to BASC, it is unlikely that the market would sustain nonfirm energy prices at the level of either cap. When California decremental fuel costs are relatively close to BASC, the market itself, not BPA's rate cap, will limit the nonfirm energy price. Id., 3. BPA's rate cap would not preclude prices equal to 75 percent of decremental cost, as recommended by NWP, until PSW decremental costs approached 40 mills/kWh. Id. With BPA's rate cap, only when PSW decremental costs are close to twice BPA's average cost of nonfirm energy would the cap hold nonfirm energy prices below 75 percent of decremental cost.

The other benefit NWP ascribes to its proposed rate cap is that the purchaser is guaranteed greater benefits than under BPA's cap when PSW decremental costs substantially increase. Opatrny/Peters, NWP, E-NP-01, 16. This claimed benefit seems illusory. NWP proposes that the rate cap not extend beyond the test period of this case. Opatrny/Peters, NWP, E-NP-01, 16. NWP admits that NWP expects decremental costs in the PSW to remain relatively close to BASC over the rate period. Id., 15. Thus, while in theory NWP's rate cap would be lower than BPA's cap when PSW decremental costs are high, in practice NWP proposes to eliminate the cap before this occurs.

An alternative approach, also advanced by NWP, is a long-term commitment always to price nonfirm energy equal to 75 percent of California's decremental costs. Initial Brief, NWP, E-NP-01, 14. NWP asserts that this pricing strategy is consistent with the real expectations of the PSW utilities and California regulators. Id. However, the passage in cross-examination that NWP cites in support of this statement leads to a different interpretation. In that portion of the transcripts, CEC witnesses state that the reasons for suggesting using 80 percent of decremental cost are that, although CEC knows that BPA's energy is priced below decremental cost, on the hour the purchaser does not know "what is actually going to happen." This uncertainty, coupled with NWP advocating rates to the PSW in the range of 75 to 90 percent of decremental cost, leads CEC to conclude that 80 percent is a reasonable assumption for future BPA nonfirm prices unless the rate cap prescribes a different level. Marcus, CEC, TR 2226-2227.

Notwithstanding the reason for advocating a long-term commitment to charge 75 percent of California decremental cost, this particular approach to a rate cap is incompatible with and too rigorous a standard to apply to a cost-based rate. First, decremental cost information is not required to purchase nonfirm energy at the NF Standard rate. Consequently, there is no way to verify or assure, before the fact, that the rate actually offered in any hour is exactly equal to 75 percent of California actual decremental costs. Of course, this

presupposes one could reasonably calculate decremental costs on a regional basis. NWP has not submitted evidence of how this calculation would be made. While NWP proposes using a production simulation model to determine decremental cost, it is not clear that any model contains the degree of accuracy necessary to meet the standard suggested by NWP on an hourly basis. Further, even if actual data were available, the administrative and monitoring requirements would be unreasonably burdensome. In fact, use of actual data raises many of the same implementation problems associated with a share-the-savings rate. Metcalf/Griffin, BPA, E-BPA-24, 22.

Finally, production model results, as amply illustrated in NWP's modeling efforts, depend on the assumptions and data inputs used. See generally Branchcomb/Peters, NWP, E-NP-02. Using a production simulation model to calculate PSW decremental costs, CEC points out, lacks predictability if BPA is able to control the input data. Chamberlain et al., CEC, E-CC-02, 20.

NWP's proposed cap ignores the fact that when California's decremental costs are high, the rate actually charged under a cost-based rate will be significantly below this level. NWP's proposed cap will result in a cap that is artificially higher than the rate BPA would expect to charge. At this artificially higher level, QF development may be cost-effective. In other words, NWP's proposed cap merely mirrors, as the NWP acknowledges, California regulators' current perceptions of future nonfirm energy rates. Initial Brief, NWP, B-NP-01, 13. Consequently, NWP's cap will not be an effective tool to evaluate the benefits of nonfirm energy purchases as opposed to QF development.

CEC takes the opposite position and advances a cap based solely on BPA's cost. Chamberlain et al., CEC, E-CC-01, 38. A cap based solely on BPA's cost, CEC notes, would provide long-term rate stability because gas and oil costs, and consequently California decremental costs, are more volatile than BPA's average system cost. Id., 40. CEC proposes a cap equal to 120 percent of BASC. With this type of cap, when California's decremental costs exceed BPA's cost, CEC argues, BPA will recover more than its average cost of nonfirm energy. Id., 42.

CEC's cap is attractive because of its administrative ease. However, because it explicitly severs any relationship between the price BPA will charge for nonfirm energy and California decremental cost, it may prove too restrictive over the long term. Melton et al., BPA, E-BPA-59, 4. In asserting that a cap based on 120 percent of BASC will not prevent cost recovery, CEC appears to focus on near-term conditions without considering the possibility that over the long run conditions may change. For instance, changes in PSW resource mix, the Southern Intertie capacity, or both could lead to situations where nonfirm energy is displacing coal or other lower-cost thermal resources more often. Melton et al., BPA, E-BPA-59, 4. A flat cap of 120 percent of BPA's cost may not allow the degree of upward flexibility needed to recover on average the cost of nonfirm energy. Id. In fact, in ER-6, the CEC's own analysis indicates that for Northern California, baseload resources will be the marginal plants a large percentage of the time. 1986 Electricity Report, 3-15. The CEC noted in ER-6 that this situation for Northern California exists without additional resources being brought into the

system. Id. CEC's future resource decisions could impact these results. For Southern California, CEC's analysis indicates that the type of resource on the margin varies dramatically with water conditions. Id., 3-20.

CEC's objections to the inclusion of PSW decremental cost in the NF rate cap ignores the specific formula proposed by BPA. As PSW gas and oil costs rise above BPA's costs, the cap increases only .3 mills per kWh for every 1 mill per kWh increase in PSW costs. A cap based solely on BPA's cost infringes on the design of nonfirm energy rates. CEC's proposed cap could seriously inhibit future nonfirm energy rate designs based on a share-the-savings approach. Melton et al., BPA, E-BPA-59, 4. CEC's cap, coupled with the implementation problems associated with a share-the-savings rate, clearly reduces the incentive to pursue such a rate. Of course, the conflict between CEC's proposed rate cap and future rate designs based on share-the-savings principles could be minimized or eliminated. One way to minimize such a conflict would be to set a higher percentage--200 percent of BASC for example. However, a high flat cap would not provide the CEC with an accurate signal of BPA's future nonfirm energy pricing expectations. In addition, a higher fixed cap would not dispel CEC's concerns regarding the relationship between BPA's price of nonfirm energy and California's decremental costs. The most direct approach to alleviate CEC's concerns about the relationship between BPA's rates and California decremental costs is to establish this relationship in the cap. In order to do this the rate cap formula needs to explicitly consider California's decremental costs. Melton, BPA, TR 2135.

Another approach that could harmonize a rigid rate cap with future rate design flexibility would be to apply the cap only to BPA's current and future cost-based nonfirm energy rates. This approach would eliminate the incompatibility between an inflexible rate cap and a rate tied to purchasers' decremental costs. CEC's concerns relating to future rate predictability appear to be directed more to BPA's cost-based nonfirm energy rates than to share-the-savings rates. CEC asserts that the reason other sellers of economy energy to California, specifically the Inland Southwest, have not been approached to provide predictability through a rate cap is that these transactions take place under umbrella contracts which define the terms of transactions. Such terms include pricing arrangements based on split-the-savings rates. Jones, CEC, TR 2193. CEC acknowledges that split-the-savings contractual provisions provide a basis to generally predict future economy energy prices. Id.

Nevertheless, CEC argues that BPA's desire to maintain rate design flexibility could be interpreted by some as an indication that BPA will retain a cost-based rate approach only until California decremental costs rise to where a share-the-savings strategy would allow higher BPA recoveries from California. Chamberlain et al., CEC, E-CC-03, 5, footnote 1. While such an interpretation could be made if the rate cap did not apply to share-the-savings rates, this interpretation is specious if the cap applies to all future nonfirm energy rates, no matter what design. It therefore appears appropriate to design a cap which meets CEC's needs for long-term rate predictability but does not confine the design of the nonfirm rate in the

future. These objectives cannot both be met with CEC's proposed cap, but can be achieved if the rate cap reflects both BPA's costs and PSW decremental fuel costs.

The DSIs suggest that a cap would not be necessary if BPA sold its nonfirm energy under a conventional share-the-savings rate. "The structure of a share-the-savings rate ensures that every transaction will benefit the purchaser, no matter what happens to the purchaser's decremental cost." Schoenbeck, DSI, E-DS-04R, 2. While the DSIs' reasoning may be correct, BPA has not adopted a share-the-savings rate as the primary rate for nonfirm energy transactions. A share-the-savings rate concept contains implementation problems which have not been addressed. It would be premature to commit to use of a share-the-savings rate until BPA has sufficient experience under such schedules to be assured that transactions under this type of pricing mechanism can be sustained over the long term.

Decision

The cap should be neutral to future designs of the BPA's nonfirm energy rate, whether cost-based or value-based, as long as it provides assurance of benefits to the PSW if gas and oil prices rise. A formula which reflects the costs of both regions is a balanced approach that meets this objective. A cap which explicitly establishes the relationship between the highest rate BPA could charge and PSW decremental fuel costs allows the CEC to determine the highest rate BPA could charge to meet the market under a worst-case scenario. The formula for the Nonfirm rate cap will be the greater of BPA's average system cost (BASC) or BASC plus 30 percent of the difference between BASC and PSW fuel costs.

Issue 5

How should the PSW decremental fuel cost component of the rate cap be determined?

Evaluation of Positions

BPA proposed that a spot market price for oil serve as a proxy for decremental fuel cost adjusted for transportation and other costs. Moorman/Margeson, BPA, E-BPA-41, 3. The Singapore oil price reported in Platt's Oilgram Price Report was proposed to be used as the indicator of PSW decremental fuel cost because it met five criteria better than any other available indicator. These criteria are that: (1) the indicator should not be subject to control or possible manipulation by either BPA or the utilities; (2) the indicator should minimize potential uncertainty and dispute; (3) the indicator should be timely; (4) the indicator should be publicly available; and (5) the indicator should accurately approximate PSW decremental fuel cost. Moorman/Margeson, BPA, E-BPA-41, 3-4. In addition, the Singapore oil price is linked through market forces to PSW oil and gas prices. Moorman/Margeson, BPA, E-BPA-41, 6.

NWP proposes that BPA use a production cost model to derive PSW decremental costs. Opatrny/Peters, NWP, E-NP-06, 5. This model, ELFIN, uses data compiled from a number of different reports and estimates the decremental cost of the marginal generating resource by peak and offpeak hour. Initial Brief, NWP, B-NP-01, 5-8. The DSIs favor NWP's version of the cap. Initial Brief, DSI, B-DS-01, 33; Schoenbeck, DSI, E-DS-04R, 13.

CEC opposes the inclusion of PSW decremental costs in the rate cap. Chamberlain et al., CEC, E-CC-01, 28, 40. If PSW decremental costs are included in a rate cap, CEC asserts that a proxy based on oil prices is inappropriate. Id., 30 and 32. Instead, CEC proposes that the PSW decremental fuel cost proxy be set equal to the average "tailblock" (Tier II) CPUC tariff for natural gas sold to electric utilities. Id., 32.

It is the ability of the Singapore oil price to meet the fifth criterion, the ability to accurately approximate PSW decremental fuel costs, that draws criticism from NWP and CEC. CEC asserts that during the period when the proposed rate cap is in effect, gas is likely to be the marginal fuel. Chamberlain et al., CEC, E-CC-01, 32. CEC contends that the Tier 2 price of gas, not the price of oil, should be used to approximate PSW decremental fuel cost, because oil is so expensive that it is very rarely the marginal fuel in California. Id., 30. NWP recommends that PSW decremental costs reflect not only the margin fuel price, but also heat rate variability. Opatrny/Peters, NWP, E-NP-01, 4.

While BPA expects the Singapore price not only to track PSW utilities' decremental oil costs but also to track PSW utilities' decremental gas costs over the long term, NWP and CEC arguments that gas costs should be also included in the determination of PSW decremental fuel cost have merit. A cap tied to only one fuel, as NWP correctly points out, cannot capture all the variations and uncertainties of this market. Id., 10. Structural shifts in energy markets could prevent market forces from causing gas and oil prices to converge. For instance, near- and long-term gas supplies at prices below those for oil are plentiful enough to meet expanding gas demands caused by switching to gas from oil. Moorman/Margeson, BPA, E-BPA-62, 4. Under this situation, BPA's oil price proxy could become significantly higher than actual decremental gas costs over the long-term planning horizon. Id. BPA agrees with NWP that both oil and gas prices should be used in determining PSW decremental fuel cost rather than using either one exclusively. Opatrny/Peters, NWP, E-NP-01, 9. Oil could conceivably become the marginal fuel for extended periods of time, in which case, as NWP notes, a PSW decremental fuel cost formula based exclusively on gas prices could prove inaccurate. Id., 4.

While BPA agrees that gas should be included in the decremental fuel proxy, the procedures proposed by NWP and CEC to accomplish this contain major flaws and limitations. Use of a production cost model as proposed by NWP has serious shortcomings. First, because the model would require large amounts of data, the potential for disputes and uncertainties increases and the more data required, the higher the chances that data series initially used might become publicly unavailable later. Second, as CEC notes, selection of data and how the model is solved, which would be controlled by BPA, can affect the

outcome. Chamberlain et al., CEC, E-CC-02, 19. Finally, a computer model does not usually result in perfect accuracy. Indeed, NWP acknowledges that there are some differences between its modeling results and other sources. Branchcomb/Peters, NWP, E-NP-02, 21.

CEC's proposal to use a weighted average of Tier II gas rates for electric utilities is also flawed. First, Tier II gas rates do not include substantial amounts of natural gas demand charges that must be paid by the utilities if they are to be able to consume gas. To the extent these are avoidable long-term expenses, NWP argues that these charges should be included in the determination of PSW decremental fuel cost. Opatrny/Peters, NWP, E-NP-01, 14. Second, future regulatory actions can change the applicability of Tier II gas rates for electric utility gas purchase or eliminate them altogether. The fact that CPUC can, and in the past has, approved restructured gas tariffs that directly influence PSW utilities' decremental fuel costs further raises a potential for these tariffs becoming a source of dispute, uncertainty, or even manipulation. Melton et al., BPA, E-BPA-59, 12.

An alternative approach, to factor both gas and oil prices in the decremental fuel proxy, is to rely on an independent source of published gas and oil prices submitted by electric utilities. The Energy Information Administration (EIA) of the U.S. Department of Energy provides such an independent source for this information. EIA produces and publishes the Electric Power Monthly (EPM), which contains electric utility fuel prices for both gas and oil. The fuel price data published by EIA is compiled from data submitted by utilities for each fossil-fueled plant having a generating capacity of 50 or more megawatts (FERC Form 423 submittals). Data from the FERC Form 423 are filed monthly and therefore are more timely than the FERC Form 1 data recommended by NWP. Updates of the price and generation data appearing in EPM can be obtained in advance of publication at the end of each month by calling EIA directly. However, the EPM price and generation data can still lag the current month by as much as 5 months. An adjustment for time lag and seasonality can correct this.

Using published fuel prices from EPM to approximate PSW fuel costs does not contain the same potential for control or manipulation as the sources proposed by CEC and NWP. The data are publicly available in a timely manner. Furthermore, the uncertainties and potential for disputes are minimized because these fuel prices are routinely compiled from an extensive survey of electric utility plants. Finally, EPM reports both gas and oil prices. Consequently, a formula using both fuel cost can be developed in order to capture the variations in both gas and oil prices.

Decision

Both gas and oil prices are factored in the PSW decremental fuel costs component of the NF rate cap. A proxy incorporating both these costs provides a better indicator of changes in fuel price and uses in California. The proxy for PSW decremental fuel is based on data published in EPM. Both gas and oil

fuel costs are included on a weighted basis in the formula. The EPM fuel price data are adjusted to correct for seasonality and time lag.

Issue 6

How should BPA's costs be determined for the rate cap proposal?

Evaluation of Positions

For the rate cap, BPA's costs are based on an average system cost approach. The average system cost approach recognizes that, in a hydro-thermal system with substantial hydro storage capability such as BPA's, it is difficult to determine the true incremental cost associated with power sold in any given hour. Melton/Margeson, BPA, E-BPA-25, 10. Energy sold at any given hour may be due to resources currently on line, resources previously run and stored in the reservoirs, or resources planned to be brought on line in the future permitting the reservoirs to be drawn down for the current sale. Id. Furthermore, use of an average system cost approach has additional merits. It is straightforward and difficult to manipulate. Id. Consequently, it enhances the predictability the cap seeks to provide in that it is not affected by changes in future cost allocation decisions by BPA, FERC, or the courts. Id., 11. To calculate BPA's average system cost (BASC), BPA's total revenue requirement for the rate period is divided by BPA's total system energy load assuming average water over the same time period. Id.

No party took issue with the average system cost approach for purposes of establishing an NF rate cap. CEC, however, suggested that BPA erred in the calculation by including both power and wheeling costs in the determination. Chamberlain et al., CEC, E-CC-01, 37. CEC reasons that because wheeling rates recover wheeling costs, it is inappropriate to include these costs in the determination of BPA's average system cost. Id.

CEC is correct that wheeling rates will recover wheeling costs. However, this does not necessarily lead to the conclusion that such costs should be removed from a determination of the average cost of producing and distributing a unit of output over BPA's system. The Federal transmission grid is an integrated system. The same transmission facilities over which BPA provides wheeling services can also be used to deliver BPA power. While it is appropriate to recognize the different uses of a facility to assign costs between specific customer classes, delineating customer-specific costs is not necessary to determine the average cost of delivering power for purposes of establishing a long-term rate cap. CEC's suggestion raises the very issue the average system cost approach sought to avoid, which was to insulate the rate cap from being affected by cost assignments to various customer classes. Melton, BPA, E-BPA-25, 10-11. Using total system cost meets CEC's objective of predictability. A subset of total system cost is less predictable than total system costs because the relationship between the FCRTS costs assigned wheeling customers and the FCRTS costs assigned nonwheeling customers may change over time.

Decision

BPA's costs for the rate cap will be based on BPA's average system cost (BASC). All of BPA's costs, including the entire Federal transmission system costs before considering revenues from services provided over this system, are appropriately included in the determination of BASC. Since these costs cannot be manipulated, this measurement provides the CEC with predictability the cap is to achieve.

D. Marketing Linear Programming and Nonfirm Revenue Analysis Program

In this proceeding, BPA relied on two separate but related models to derive forecasted revenues from economy energy sales. The Marketing Linear Programming (LP) model forecasts the market for nonfirm energy and surplus firm power sales in California, and the Nonfirm Revenue Analysis Program (NFRAP) model forecasts nonfirm (NF) energy and flexible surplus firm power (SP) sales in the Pacific Northwest (PNW) and Pacific Southwest (PSW). Revenue from sales of flexible SP and nonfirm energy can constitute a significant portion of BPA's total revenues. These sales are unstable because they depend in part on water conditions, differences in firm loads, resource performance, and market conditions. Technical issues were raised during these proceedings regarding the accuracy of BPA's forecasted market for SP and NF sales to California. Other issues were raised regarding modeling the proposed nonfirm energy Market Expansion rate and the size of the PSW market for Market Expansion rate sales.

Issue 1

How should BPA model nonfirm energy sales at the Market Expansion rate to California?

Evaluation of Positions

BPA's nonfirm energy rate schedule in the initial proposal, included a Standard rate and a Market Expansion rate component. A complete discussion of the operation of these rates is found in this chapter. In the NFRAP, BPA did not project any nonfirm energy sales to the PSW at the Market Expansion rate. BPA, E-BPA-06A, 73-74. NWP urged BPA to modify the NFRAP to reflect Market Expansion sales to the PSW and testified that under average water conditions such sales would provide at least $25 million and possibly $70 million in additional revenues to BPA. Howard et al., NWP, E-NP-05, 5-8.

BPA responded by modeling Market Expansion sales to California and discussed the results of this effort in rebuttal testimony. Wedlund/Bliven, BPA, E-BPA-55, 4. BPA"s initial attempt to model Market Expansion sales to California indicated a potential market of $50 million per year assuming the average of 40 water conditions, and $15 million per year under 1939 water conditions. Wedlund/Bliven, BPA, E-BPA-55, Attachment A. BPA concluded that

the potential market for Market Expansion sales to California was substantially lower than the $70 million market claimed by NWP. Wedlund/Luttmer, BPA, E-BPA-46A2, 3.

BPA subsequently reduced its own forecast of revenues from nonfirm energy sales at the Market Expansion rate to California, in all water conditions, by two-thirds. Wedlund/Luttmer, BPA, E-BPA-46A2, 3. This reduction was warranted for three reasons. First, California utilities have historically purchased minimal amounts of nonfirm energy at BPA's previous market expansion rates (called "displacement" rates). This was due, in part, to a reluctance of California utilities to provide BPA with resource qualification data which is a prerequisite for Market Expansion sales. Id. Second, there is often limited Intertie capacity for nonfirm energy sales at the Market Expansion rate because of California use of the northern California portion of the PNW/PSW Intertie. Id. Third, there was a relatively low level of displacement rate sales to California in 1986. BPA testified that a similar level of sales could be expected during the rate test period. Id.

WPAG argues that a reduction in nonfirm energy sales at the Market Expansion rate is not necessary. McGary et al., WPAG, E-WA-05, 24-25. WPAG maintains that while a reduction in Market Expansion rate sales might be warranted under average water conditions, a reduction under 1939 water conditions is not warranted because water conditions in northern California are closely correlated with PNW hydro conditions. Thus, there would be available capacity on the northern portion of the California Intertie under 1939 water conditions which would permit BPA to make Market Expansion rate sales to California. McGary et al., WPAG, E-WA-05, 6; Initial Brief, WPAG, B-WA-01, 26.

WPAG acknowledges that historically California utilities have been reluctant to prequalify resources and provide decremental cost data to BPA. Initial Brief, WPAG, B-WA-01, 27. However, WPAG argues that BPA could avoid the impediment of California utilities' reluctance to prequalify resources for displacement by relying on available published data. Initial Brief, WPAG, B-WA-01, 27. WPAG argues that Southwest utilities have demonstrated more willingness to share decremental cost data when it is to their advantage and cites their participation in the Western States Power Pool and Western Electricity Study as evidence. Id. WPAG concludes that the two-thirds reduction in Market Expansion revenues under 1939 water conditions is not warranted. Id., 28. Peters/Shannon, PPC, E-PP-12, 4.

BPA agrees in part with the position expressed by WPAG. It may be inappropriate simply to reduce forecasted revenues from Market Expansion sales by two-thirds during poor water conditions. It is appropriate, however, to reduce the California market remaining for Market Expansion sales after Standard rate sales have been estimated. Although this reduction in the market has the effect of reducing revenues under average and better than average water conditions, it will have no revenue impact under 1939 water conditions.

The PPC and NWP take exception to BPA's decision to reduce by two-thirds the estimated California markets remaining for Market Expansion rate sales.

The PPC and NWP argue that this reduction in Market Expansion rate sales to California results in a corresponding reduction in revenue that causes BPA to dramatically understate the amount of revenue protection provided by the use of 1939 water conditions. Exceptions, PPC, R-PP-01, 27-28; Exceptions, NWP, R-NP-01, 4. Based on historical experience, BPA believes that this adjustment is warranted.

During FY 1987, BPA received $0.2 million from below-cost displacement (market expansion) sales to California. Statement A, Table A-7. In FY 1986, when water conditions were average, BPA received $13 million from low-cost surplus firm and nonfirm sales to PSW utilities. Initial Brief, WPAG, B-WA-01, 27. Only $6.3 million of the $13 million resulted from Market Expansion (or displacement) rate sales. Wedlund/Luttmer, BPA, E-BPA-46A2, 3. In FY 1984-85, when fuel prices were higher than FY 1986, there were virtually no low-cost displacement sales. Wedlund, BPA, TR 2811. As such, regardless of whether alternative fuel prices have been low or high, BPA revenues from "displacement" sales to California have been minimal. There is no persuasive evidence in the Record that there will be a dramatic increase in low-cost displacement sales to California, during this rate period.

Decision

BPA will model Market Expansion rate sales in the manner described above so that projected sales will not differ dramatically from historical experience. There is compelling historical evidence that revenues from Market Expansion sales will not be significant under any conditions.

Issue 2

Should BPA incorporate nomograms in the Marketing LP model to simulate simultaneous interregional transfer limits?

Evaluation of Positions

In the initial proposal, BPA did not consider the impact on energy exports to California from regions other than the PNW. NWP urged BPA to incorporate nomograms into the Marketing LP model, to simulate interregional energy transfer limits due to loop flow between the desert Southwest, the Rocky Mountains, and California. Howard et al., NWP, E-NP-05, 3-5. This action would have had the effect of increasing the forecasted PSW market for PNW power.

BPA disagrees with the use of nomograms for numerous reasons. First, nomograms are only relevant for existing interconnections but not for intertie expansions or additions. This means that any nomograms which might be accurate now would not be accurate when the HVDC terminal expansion occurs during FY 1989. Wedlund/Bliven, BPA, E-BPA-55, 3-4. Second, the proposed nomogram is inaccurate and nomograms for all transmission interconnections would be necessary for an accurate representation. In other words, the data supplied by NWP on this issue is inaccurate and incomplete. Id. Third, the addition of nomograms would substantially increase the complexity of the

Marketing LP model. The additional cost (in time, money, and other resources) may far outweigh any potential benefit--which has not been identified. Id. These reasons were not challenged by NWP or any other party.

Decision

The addition of nomograms to the Marketing LP model is not warranted at this time. The additional administrative burden likely would outweigh any potential benefit.

Issue 3

Should the Marketing LP model inputs be changed to incorporate actual rates and pricing structures between the desert southwest and California utilities?

Evaluation of Positions

In the initial proposal, BPA relied upon the marginal cost of production for generation units in the inland Southwest and California to determine the market for PNW exports. NWP urged BPA to use actual rates and pricing structures rather than marginal production costs in the Marketing LP model for modeling sales between the desert southwest and California utilities. Howard et al., NWP, E-NP-05, 2-3. NWP took exception with BPA's draft decision not to incorporate actual rates or pricing structures in the Marketing LP model when estimating the demand for economy energy in California. NWP maintain that BPA's position is without merit because BPA did not demonstrate that the Marketing LP could not be restructured to rely on actual pricing structures and also that BPA had sufficient information to calculate actual pricing structures. Exceptions, NWP, R-NP-01, 14-15.

There are three reasons why BPA believes it is appropriate to rely on the marginal costs of resources in the Marketing LP model to determine transactions between regions. First, NWP's proposal could not be incorporated into the Marketing LP model because the model is structured to rely on incremental fuel costs. NWP offered no information which allows BPA to evaluate or incorporate the suggested change. Wedlund/Bliven, BPA, E-BPA-55, 2. Second, actual rates and pricing structures do not allow the flexibility for change as market conditions change--and rate structures and prices change with changes in market conditions. Id. Finally, deliveries from the Inland Southwest to California utilities are not constrained by rate schedules or pricing structures, but by the incremental cost of resource operation. Id.

The NWP apparently believe that its suggestions would result in increased revenues from export sales from the PNW. BPA, however, does not agree with this conclusion. Sales are ultimately constrained by the incremental cost of generation because utilities will not sell at a price lower than the savings they could realize by shutting down their resource or reducing its output.

In addition, the NWP contend that BPA has sufficient information to calculate actual pricing structures for transactions between the inland

Southwest and California utilities. Exceptions, R-NP-01, 14-15. This contention is erroneous. BPA testified that it lacks the necessary information to make this calculation. Wedlund/Bliven, BPA, E-BPA-55, 2. Moreover, neither NWP or any other party provided BPA with the necessary data. In any event, there has been no demonstration that current actual rates or pricing structures would remain stable during the rate period, and no evidence introduced demonstrating that the recommended action would make any significant difference in the forecast of revenues. Id.

Decision

There is no evidence that the use of actual rates and pricing structures in the Marketing LP model for transactions between the inland Southwest and California would significantly change BPA's revenue forecasts. Therefore, the use of incremental cost inputs to the Marketing LP will not be changed.

Issue 4

Should the Marketing LP model identify different demand curves for individual California utilities?

Evaluation of Positions

The Marketing LP model separately forecasts the demand for PNW power by both Northern California and Southern California. This information is aggregated prior to determining revenues from export sales. NWP urges BPA to use the Marketing LP model to forecast demand curves for individual California utilities to improve the model's accuracy. Howard et al., NWP, E-NP-05, 3.

BPA identified four reasons why forecasting demand curves for individual utilities is not beneficial to BPA's modeling efforts. First, the proposed modification of the model would not improve the accuracy of the Marketing LP forecast given BPA's assumption that all California transactions are modeled to occur at the same price. Wedlund/Bliven, BPA, E-BPA-55, 2-3. Second, the model is not designed to look at California utilities in isolation. To separately model demand for power by individual California utility entails a great deal of modeling effort that would likely not improve the accuracy and usefulness of the model's forecasts. Id. Third, even if BPA could separately model demand by individual California utility, BPA would not necessarily be able to sell nonfirm energy at different prices to different California utilities because of the ability of California utilities to minimize production costs by engaging in transactions amongst themselves. Id. Fourth, NWP has not demonstrated that this proposal would result in a significant change in projected revenues, improve the accuracy of the model, or could be accommodated within the model. Id.

Decision

BPA does not perceive any meaningful benefit from separately forecasting the demand for PNW power by individual California utility. Thus, the demand

for PNW power by California utilities will not be modeled on a utility-by-utility basis.

Issue 5

Should BPA reshape the surplus firm open market (SPOM) power in the RAM to ensure displacement of WNP-3 combustion turbine output?

Evaluation of Positions

In the initial proposal, BPA shaped its available SPOM to conform to the 1986-87 Coordination Agreement. WPAG contends that BPA should reshape the SPOM in a way that displaces the operation of the combustion turbines used to provide WNP-3 exchange power when there is insufficient secondary energy to displace the combustion turbines. Specifically, WPAG suggests reshaping the SPOM to make more available in the winter months. McGary et al., WPAG, E-WA-02, 38-39; E-WA-04, 24-25.

WPAG apparently did not realize, however, that reshaping the SPOM into the winter to ensure displacement of the combustion turbines would result in increased spill in the winter and spring months and reduced sales in the fall months. The resulting loss of revenue would be much greater than the savings gained by displacing the combustion turbines. Wedlund/Bliven, BPA, E-BPA-55, 7.

Decision

The existing shape of SPOM is reasonable. Reshaping to ensure displacement of combustion turbines is not cost-effective.

CHAPTER IX

WHOLESALE POWER RATES

A. General Rate Design Issues

1. Irrigation Discount

From 1979 through the present, many of the features of BPA's firm power rates have helped reduce the power costs of regional irrigation consumers. The uncertainty of the economic health of the agriculture sector in the long run, coupled with the financial hardship this sector has been experiencing and the importance of agriculture to the region's economy, led BPA to develop an irrigation discount for the 1985 rate period (July 1985 through September 1987). 1985 Rates ROD, WP-85-A-02, 337.

Issue 1

Should BPA include an irrigation discount in the PF-87 and NR-87 rate schedules?

Evaluation of Positions

Almost half of the comments received in BPA's field hearings related to the relationship of agriculture to electricity rates. Of the 165 comments received by BPA in 8 field hearings, 74 dealt with the subject of irrigated agriculture. Many participants cite large increases in their electricity bills over the last few years. For example, see Towery, Eugene Hearing, 44; Gillette, Eugene Hearing, 29; Kopenhaven, Spokane Hearing, 49-50; Zagelow, Spokane Hearing, 14-17. In the Richland area, several irrigators noted that BPA's proposed rate increase would cause them to reduce irrigated acreage substantially. L. Hector, Richland Hearings, 21; Mueller, Richland Hearing, 27. Some related that they have shifted and would continue to shift to diesel fuel pumps as the price of electricity increases. Bell, Burley Hearing, 54-55; Aikele, Burley Hearing, 42-44. For some irrigators, electricity represents a relatively large proportion of their costs. Renta, Richland Hearing, 19; Quirk, Spokane Hearing, 7; Hardt, Spokane Hearing, 23. Most of the participants commenting on irrigated agriculture support the proposition that irrigated agriculture is experiencing especially difficult economic conditions at the present time. Initial Brief, NIU, B-NI-01, 11; Crook, Lincoln County Farm Bureau, Jackson Hearing, 58; Schorzman, Spokane Hearing, 35; Rothwell, Burley Hearing, 40-42. In addition, many farmers in the region wrote letters expressing similar concerns.

These comments are an important consideration in evaluating the irrigation discount. However, it is difficult to aggregate statistics from these comments and accurately infer their impact on the entire region. The comments generally show that there are areas within the region where irrigation electricity loads are sensitive to electricity rates.

NIU supports BPA's proposal to continue the irrigation discount in the 1987 rate period. Initial Brief, NIU, B-NI-01, 3. First, NIU argues that preservation of BPA revenues helps justify the irrigation discount because BPA's irrigation load is elastic. That is, increased rates to irrigators would cause decreased loads and therefore reduce BPA revenues. Lovelin, NIU, E-NI-07, 2-3. (See also Martin, NIU, E-NI-01, E-NI-05, E-NI-08.) Second, NIU cites the economic crisis facing the agriculture industry. Lovelin, NIU, E-NI-07, 4. Third, NIU argues that an irrigation discount is justified on cost of service principles. Kavanaugh, NIU, E-NI-04, E-NI-06, E-NI-09; Exceptions, NIU, R-NI-01, 3. NIU proposes that continuation of the irrigation discount can be viewed as a proxy to revising BPA's cost of service methodology. Lovelin, NIU, E-NI-07, 5. NIU recommends that BPA adopt NIU's cost of service methodology, which would result in maintaining the average irrigation rates at the PF-85 level. Initial Brief, NIU, B-NI-01, 3.

ICUA and OFBF also support continuation of the irrigation discount. ICUA points to the distressed irrigated agricultural economy and the impact of irrigated agriculture on other parts of the region. Initial Brief, ICUA, B-IU-01, 8. ICUA supports the NIU position that irrigated agriculture demand for electricity is elastic. Id. OFBF emphasizes the large secondary impacts from irrigated agriculture and the continuing economic recession in the agriculture sector. Initial Brief, OFBF, B-OF-01, 4. PNGC argues that the irrigation discount is a long-term revenue enhancement measure, not a subsidy. Exceptions, PNGC, R-PN-11, 5.

WPAG, in contrast, proposes that the irrigation discount be discontinued. McGary et al., WPAG, E-WA-04, 32. WPAG considers the irrigation discount an unnecessary subsidy which forces the Administrator into making social judgments. Exceptions, WPAG, B-WA-02, 33. WPAG asserts that the irrigation discount program costs BPA's other customers more than BPA gains from the program. McGary et al., WPAG, E-WA-04, 33. WPAG argues that BPA would increase its revenues by ending the discount and selling any displaced power in the export market. McGary et al., WPAG, E-WA-04, 33. WPAG also contends that it is unfair and inequitable for one economically depressed area such as in the timber dominated counties, to subsidize another less depressed area. McGary et al., WPAG, E-WA-01, 20. WPAG argues that large subsidies from the U.S. Department of Agriculture are already assisting irrigated farms in the region and a discount on electricity would counter the purpose of those subsidy programs. Initial Brief, WPAG, B-WA-01, 17.

PGP also proposes that the irrigation discount be eliminated. PGP argues that the justification for extending the discount based on farmers experiencing short-term economic distress is based on ability to pay rather than on cost of service. Helgeson/Opatrny, PGP, E-PG-06, 4. PGP further contends that the justification does not demonstrate near-term and long-term revenue benefits for BPA and its customers. Id.

BPA proposes to offer the irrigation discount under the PF-87 and NR-87 rate schedules for the same reasons the discount was offered in 1985. One of these reasons was the financial hardship of Pacific Northwest irrigated agriculture. This financial hardship still exists. Another reason was the adverse economic conditions facing irrigated agriculture in the Pacific

Northwest. These conditions appear to continue, with the outlook uncertain. Finally, irrigated agriculture was an important economic sector in the Northwest in 1985, and remains as an important economic sector in the Northwest.

In the current rate proceeding, BPA is proposing to eliminate the seasonal differentiation of demand charges. The elimination of the seasonally differentiated demand charges has an adverse impact on rates charged to irrigators because it causes the summer demand charges to increase. Therefore, BPA proposed not only to maintain the discount but to increase it over the next rate period. The increase of the discount is to allow power costs of irrigators to remain a constant percentage below power costs of other Priority Firm Power customers.

It is BPA's position that short-run irrigation demand for electricity on a regional basis is probably price inelastic. Thus, any discount is expected to decrease revenue during the rate period from this consumer sector. By extending the discount, BPA is continuing to help this sector weather a short-term downturn so that it remains healthy in the long term. In so doing, BPA will protect its ability to generate additional revenues in the future when the demand for the region's agricultural products increases. Whitelaw, ICUA, E-IC-01, 8.

It is clear that the economic difficulties facing the agriculture industry provide a major justification for the discount. Roghair/Margeson, BPA, E-BPA-27, 6. However, an irrigation discount alone is not expected to increase the demand for irrigation electricity in the short run, especially during times of economic difficulties. Irrigation rates are only one component of the costs and returns to farmers. Market demand and market prices affect the economic viability of the PNW farmers more than any production cost item. Moorman/Schneider, BPA, E-BPA-52, 12. Agriculture remains in a recession which does not equally affect all agricultural sectors. Moorman/Schneider, BPA, E-BPA-52, 16.

NIU's contention that BPA did not appropriately seasonally differentiate the capacity charge is addressed in Chapter V. BPA rejects NIU's arguments for changing the methodology for seasonally differentiating the capacity charge or using the discount as a proxy for the "errors." See Chapter V.C.

WPAG's characterization of the irrigation discount as a subsidy is partially correct. By providing a rate discount to irrigators, BPA must raise other customers' rates. Roghair/Margeson, BPA, E-BPA-27, 9. WPAG's argument that BPA would increase revenue by ending the discount and selling displaced power in the export market is also partially correct. Given that the irrigation load is inelastic, eliminating the discount would increase BPA revenues from irrigators in the short run. Roghair/Seifers, BPA, E-BPA-43, 2. It should be noted, however, that BPA does not justify the discount on grounds of short-run revenue enhancement. Additionally, some of the lost sales to the irrigators due to a price increase could indeed be made in the surplus market. However, regional electricity sales have a multiplier effect. That is to say, if some irrigators go out of business due to a large rate increase without the discount, other sectors of the economy will be

affected and cause an additional reduction in electricity sales within the region. Roghair/Seifers, BPA, E-BPA-43, 2.

WPAG states that the three reasons BPA implemented the irrigation discount in the 1985 BPA wholesale power rate case are no longer valid: (1) irrigators are not worse off; (2) there is no unanimous support for the discount; and (3) the irrigation discount has not maintained any irrigation loads. Initial Brief, WPAG, B-WA-01, 17.

First, WPAG contends that the financial distress of irrigated agriculture is no worse than that faced by BPA's other customers. Id. However, the evidence presented in support of this argument is weak in several respects. For example, the county comparison made by WPAG improperly relied on employment figures instead of the economic health of the industries. WPAG also failed to compare absolute income per worker, which is greater in nonagricultural communities. WPAG uses 1979-1985 data, which give a different picture from that given by 1981-1985 data. Martin, NIU, E-NI-05, 4-5; Initial Brief, ICUA, B-IU-01, 8. WPAG is correct that there is major Federal farm legislation to alleviate the financial hardship of farmers. However, much of this subsidy does not necessarily affect irrigated agriculture, but affects dryland wheat growing areas. Roghair/Seifers, BPA, E-BPA-43, 8.

Second, WPAG notes that publicly owned utilities do not unanimously support continuation of the discount. Initial Brief, WPAG, B-WA-01, 18. During the 1985 rate case only WPAG provided substantial opposition to the irrigation discount. In the 1987 rate case, PGP joins WPAG in opposing implementation of the discount. Helgeson/Opatrny, PGP, E-PG-06, 4.

Third, WPAG states that the discount has not resulted in the retention of irrigation load, but merely loses money. In support of this contention, WPAG states that irrigators received a 16.3 percent discount in the 1985 wholesale rate case, and yet reduced loads by 10 percent. Initial Brief, WPAG, B-WA-01, 18.

The WPAG analysis is simplistic and does not properly relate price changes and loads. For rate impact analysis, all other conditions must be held relatively constant. It is possible that other conditions, such as price of output or weather, may have had more impact on the demand for electricity than the price of electricity. The data relied on by WPAG do not show that an electricity price decrease causes an electricity load decrease or that some irrigation load was not retained by granting the discount. Indeed, BPA may have lost more irrigation load if not for the discount.

PGP's contention that the discount is being justified on ability to pay alone is flawed. Ability to pay in terms of financial hardship and uncertain long-run economic health is only part of the reasoning for BPA's offering the discount. The other reason is the importance of irrigated agriculture to the economy of the Pacific Northwest. Roghair/Margeson, BPA, E-BPA-27, 5. Many communities in the Pacific Northwest depend on the health of irrigated agriculture. Heitman et al., NIU, E-NI-02, 8; Minford, Spokane Hearing, 46; Green, Burley Hearing, 46. Secondary impacts from income generated in the

irrigated agricultural sector cannot be ignored. Martin, NIU, E-NI-08, Exhibit 2. The income of communities in the Pacific Northwest may increase by a multiple of the increased income to irrigators due to the irrigation discount. This additional income could allow for increased nonirrigation electricity sales in the region. Roghair/Seifers, BPA, E-BPA-43, 2. Sectors of the regional economy most dependent on irrigation have experienced a recession since 1981 and probably will continue to do so for the next few years. Martin, NIU, E-NI-01, 18-26; Oreca letter, Eugene Hearing.

Decision

Based on the uncertain long-run economic health of irrigated agriculture, the current financial hardship of Pacific Northwest irrigated agriculture, and the importance of irrigated agriculture to the Pacific Northwest, BPA includes an irrigation discount in the PF-87 and NR-87 rate schedules for this rate period.

Issue 2

What should be the level of the irrigation discount?

Evaluation of Positions

In the initial proposal, BPA reduced the April through October PF-87 and NR-87 energy rates for irrigation loads by 4.9 mills per kilowatthour. BPA, E-BPA-06, 68, 73. BPA determined the level of the discount by applying the average PF-87 rate increase to the annual average irrigation purchased power costs at PF-85 rates. Roghair/Margeson, BPA, E-BPA-27, 6. Additionally, an energy discount of 4.9 mills per kilowatthour April through October was found to insulate the irrigation load from the PF-87 summer demand charge increase while maintaining the relative annual average rates between irrigators and other Priority Firm customer loads. Roghair/Seifers, BPA, E-BPA-43, 6.

NIU, OFBF, and ICUA support an irrigation energy discount of 6 mills per kilowatthour during April through October, based on an average PF rate increase of 9.5 percent. Lovelin, NIU, E-NI-07, 6; Initial Brief, OFBF, B-OF-01, 15; Initial Brief, ICUA, B-IU-01, 9. OFBF also proposes that BPA adopt a discount level of 4.9 mills per kilowatthour or maintain average irrigation rates at the PF-85 level by adopting NIU's cost of service results. Initial Brief, OFBF, B-OF-01, 6. OFBF suggests that BPA use a combination of the 4.9 mills per kilowatthour discount and adopt NIU's cost of service results. Initial Brief, OFBF, B-OF-01, 16.

NIU argues that the discount should be sufficient to offset any rate increase to the irrigators. NIU asserts that the irrigators need a 6 mill per kilowatthour energy discount from April through October to offset an average 9.5 percent PF rate increase, arguing that <u>any</u> rate increase to irrigators at this time will cause a revenue decrease to BPA. Their logic is based on NIU's assertion that currently the demand for irrigation electricity is elastic with

respect to the price of electricity. Lovelin, NIU, E-NI-07, 3. See Chapter II.D for a full discussion of price elasticity.

ICUA suggests that the irrigation discount level of 6 mills per kilowatthour would have a minimal revenue impact on BPA and would harmonize the discount with a uniform demand charge. ICUA argues that the 6 mill discount would allow BPA to have a uniform demand charge without affecting sensitive irrigation loads. Initial Brief, ICUA, B-IU-01, 9-10. NIU estimates that a 6 mill discount could cost from $1.26 million to $3.43 million more than the BPA proposal. Lovelin, NIU, E-NI-07, 8. BPA estimates the additional cost of a 6 mill discount to be $4.5 million per year. By increasing the discount without targeting sensitive loads, BPA would be reducing revenue throughout the region without necessarily guaranteeing that the rate-sensitive loads would be maintained. BPA has an obligation to other customers to minimize the costs of programs aimed at sustaining long-term load.

WPAG proposes that the irrigation discount be eliminated or at least phased out. McGary et al., WPAG, E-WA-04, 34. WPAG suggests that the present discount should be reduced by one-third for this rate period to prevent a rate shock to the irrigators. Id. Reducing the discount during an economic recession at a time when BPA is deseasonalizing the demand charge would cause the irrigating utilities to shoulder a much larger rate increase than winter peaking utilities. Winter peaking utilities are receiving a decrease in the winter demand charge, thus benefitting from deseasonalizing the demand charge.

Economic conditions in the irrigation sector have not changed significantly since 1985 when BPA first adopted the irrigation discount. Roghair/Margeson, BPA, E-BPA-27, Attachment 1. At the same time, the record does not demonstrate that irrigators are worse off than they were during the 1985 rate case. Similarly, the record does not demonstrate that BPA's irrigation load on a regionwide basis is elastic. An irrigation load which is inelastic with respect to electricity price implies that the higher the level of the discount, the more it will cost other BPA customers.

Elimination of the seasonality in capacity charges could harm the irrigators. Given their poor economic situation, it is reasonable to mitigate these impacts with an increase in the level of the discount. However, BPA should not insulate the irrigators from the average rate increase. To allow one particular customer class to avoid the average rate increase would cause customer class inequities within the region. Roghair/Seifers, BPA, E-BPA-43, 10.

Decision

BPA will increase the current PF-85 irrigation energy discount of 3.7 mills per kilowatthour to 4.6 mills per kilowatthour, the level that will assess irrigation loads the average PF-87 percentage increase in their purchased power costs.

Issue 3

Should BPA include the irrigation discount in the Priority Firm Exchange rate schedule?

Evaluation of Positions

BPA proposes to include the irrigation discount in the Priority Firm Power rate schedule. There are two separate rates within the proposed 1987 Priority Firm rate schedule: Preference and Exchange. In the current PF-85 rate schedule, one rate applies to both preference customer firm purchases and exchange purchases.

WPAG argues that there is no requirement that BPA provide an irrigation discount to all regional irrigated agriculture. Initial Brief, WPAG, B-WA-01, 20-21. WPAG claims that the irrigation discount, if available at all, should be available only to actual energy purchased to serve actual irrigation load. Id. WPAG asserts that the discount should be totally excluded from all Exchange calculations. WPAG asserts that extending the discount to the exchange customers improperly increases the cost of the exchange. Id. WPAG claims that the irrigation subsidy is not available for the general requirements of preference customers, but only for service to irrigation load. Exceptions, WPAG, B-WA-02, 34. Therefore, including it in calculating exchange benefits is contrary to section 5(c) of the Northwest Power Act. Id.

NIU, ICUA, and PNGC object to elimination of the discount from the calculation of the exchange benefits. Exceptions, NIU, R-NI-01, 3; Exceptions, ICUA, R-IU-01, 3; Exceptions, PNGC, R-PN-01, 5. PNGC argues that BPA should not adopt a new method of calculating the exchange benefits for irrigators. Oral Argument, PNGC, TR 3042. PNGC further argues that WPAG's proposal would remove the irrigation discount from just one side of the exchange transaction, causing an unbalanced transaction that would improperly reduce benefits to the public exchanging utilities. Oral Argument, PNGC, TR 3043. BPA agrees that to the extent that the irrigation discount forms part of the purchase power cost that a public utility would include in its average system cost and exchange, including the discount in one and not the other would cause a distortion. Margeson, BPA, TR 446.

The intent of the exchange is to equalize residential and small farm rates among exchanging IOU and public utilities within the region. Margeson, BPA, TR 443. To the extent that a discount, credit, or surcharge is passed to the public agencies, the same discount, credit, or surcharge should flow through to the exchange. Id. By including the discount in both the Preference and Exchange rates, exchange benefits to the public exchanging utilities are not significantly changed by the irrigation discount.

Decision

The irrigation discount is included in both the Priority Firm Preference and Exchange rate schedules. By including the discount in both the Preference

and Exchange rates, the exchange benefits to the public exchanging utilities are not significantly changed by the irrigation discount.

Issue 4

How should the irrigation discount be structured?

Evaluation of Positions

BPA proposes that the irrigation discount be a uniform energy-only discount and apply from April through October. BPA, E-BPA-06, 66. The 1985 irrigation energy discount runs from April through August. The PF-85 and NR-85 summer demand charge season runs from May through November. The proposal to eliminate demand charge seasonality would increase the demand charge for the summer months markedly. In addition, higher winter PF-87 and NR-87 energy charges begin in September. Since almost all irrigation sales occur in the months April through October, a discount extending through October would mitigate the rate increase to irrigation loads. Roghair/ Margeson, BPA, E-BPA-27, 8. NIU, ICUA, and OFBF all support the extension of the irrigation discount period from April through October. Lovelin, NIU, E-NI-07, 6; Initial Brief, ICUA, B-IU-01, 9; Initial Brief, OFBF, B-OF-01, 13.

NIU and ICUA argue that a higher discount than BPA proposed is needed when the eligibility period is extended from April through August (1985 discount period) to April through October so that short season irrigators do not receive a disproportionate rate increase. However, NIU and ICUA oppose a split period discount, which would allow a higher discount for short season irrigators and a lower discount for long season irrigators. Lovelin, NIU, E-NI-07, 10; Initial Brief, ICUA, B-IU-01, 9. NIU contends that a higher uniform discount is needed to correct intra-regional inequities among irrigators with differing irrigation seasons. NIU asserts that the two extra months should be included without redistributing the economic benefit of the discount. Lovelin, NIU, E-NI-03, 6. NIU proposes that an irrigation discount be calculated on an April through August basis and then applied to an April through October period. Lovelin, NIU, E-NI-03, 7. However, increasing the level of the discount in this manner would not eliminate the different percentage rate increases among utilities with different irrigating seasons. Roghair/Seifers, BPA, E-BPA-43, 9.

Any time BPA designs a rate that applies regionwide, there will be differences in the annual average percentage rate increase among customers with different load characteristics due to geographical location, weather differences, or industrial patterns. The irrigation discount is no exception. BPA limited the irrigation discount in the 1985 rate case to April through August, already designated as a lower cost period for BPA. In September and October, irrigators have much greater flexibility to shift to offpeak use. 1985 Rates ROD, WP-85-A-02, 340. BPA proposes to add September and October to the 1987 discount to mitigate the large summer (May through November) demand charge increase. Roghair/Margeson, BPA, E-BPA-27, 8.

BPA suggested that splitting the irrigation discount season into two parts with two different discount levels could help correct for differences in average rate increases within the region. The May through August discount could increase and the September and October discount decrease. April would not receive a discount due to the decrease in demand charges in that month. This split discount could be done without changing the total cost of the discount to help alleviate the intra-regional equity problem. Roghair/Seifers, BPA, E-BPA-43, 6-7.

NIU and ICUA reject the concept of a split season discount, however. Lovelin, NIU, E-NI-07, 10; Initial Brief, ICUA, B-IU-01, 9. NIU argues that the net effect of a split period discount would be to reduce the aggregate benefit of the irrigation discount power to regional irrigation utilities as a whole. Lovelin, NIU, E-NI-07, 11. NIU states that the split discount would provide economic benefits to a few utilities, but at a cost to many other utilities. Id. NIU also opposes the split season discount on the grounds that a number of utilities read their meters on a seasonal or less than monthly basis. An additional reading would cost a considerable amount. Lovelin, NIU, E-NI-07, 12.

BPA acknowledges the NIU and ICUA preference for a level discount throughout the April through October period, with the understanding that shorter-season irrigators will have a slightly higher overall rate increase than longer season irrigators with the same discount.

Decision

A uniform irrigation energy discount will apply from April through October.

Issue 5

Should the irrigation discount be applied to distribution line losses?

Evaluation of Positions

NIU proposes that the irrigation discount apply to distribution line losses. NIU asserts that if losses on purchased power from BPA are not discounted, the utility will pass on the high power costs of losses to the irrigators, thereby diluting the energy discount. Lovelin, NIU, E-NI-07, 14.

BPA opposes this proposal for three reasons. First, each purchasing retail utility has different load factors and different ratemaking criteria allocating demand and energy costs to its various customer classes. Not all costs are directly passed through in the same rate design as BPA's, e.g., BPA's diurnally differentiated demand charge. 1985 Rates ROD, WP-85-A-02, 335. The manner in which each utility passes on the BPA demand charge and losses is not standard throughout the region and is not controlled by BPA.

Second, BPA has a low density discount (LDD) provision, the intent of which is to mitigate high distribution costs such as line losses. The large

majority of irrigation loads of the region receive the benefit of the low density discount. Roghair, BPA, TR 438.

Third, BPA has a responsibility to other customer classes to minimize the revenue loss caused by the discount. Applying the discount to line losses would increase the revenue loss to BPA from the irrigation discount. It would also increase the cost of administering the program because of the need to calculate and verify distribution loss percentages for all utilities with irrigation loads.

Decision

BPA will continue to apply the irrigation discount to only end-use irrigation sales. Power purchased which is lost in distribution will not qualify for the irrigation discount. The low density discount is available to alleviate the costs of distribution line losses.

Issue 6

Should the irrigation discount be targeted to particular irrigation loads?

Evaluation of Positions

WPAG asserts that the irrigation discount can help irrigators for whom electricity constitutes 20 percent or more of their total costs. WPAG proposes that if BPA chooses to offer the discount, BPA should target the discount to this group of irrigators. Initial Brief, WPAG, B-WA-01, 20; Oral Argument, WPAG, TR 3142. Studies done for BPA have identified areas where irrigators have high or long lift pumping, deep wells, limited cropping, and sandy soils. These areas are considered rate sensitive; that is, changes in electricity rates can cause relatively greater changes in energy purchased by these irrigators. McGary et al., WPAG, E-WA-03, 46; 1985 Rates ROD, WP-85-A-02, 334.

NIU argues that there is no evidence on the record to identify criteria for targeting the discount. NIU asserts that the study cited by WPAG is out of date and underrepresents the elasticity of demand in some areas of the region. Oral Argument, NIU, TR 3144. NIU asserts that the evidence shows that crop prices are down in a number of commodities and are not necessarily related to high lift areas or sandy soil areas. Id.

Encouraging inefficient operations or irrigating crops that are uneconomic is a definite concern. However, there are several problems with targeting the discount for the 1987 rate period. At the very least, targeting through a rate application could be administratively burdensome. No party in the rate case presented any specific targeting proposals. In addition, BPA needs a better understanding of the impact that the irrigated agricultural sector has on the regional economy and how the impact varies in different areas of the region.

Decision

For this rate period, the irrigation discount will be implemented on a regionwide basis. During the 1987 rate period, the irrigation discount will not be targeted to particular irrigation loads because of the administrative complexity of developing the targeting mechanism within a short period of time. Continuation of the irrigation discount will depend upon a demonstrated benefit to BPA and BPA's other customers. Such benefits may be in the form of revenues from increased irrigation load or long-run contribution to the region's economic health. One way of assuring these benefits may be to target the discount to specific areas or subclasses of irrigators. BPA will work with its customers to obtain information about the elasticity of demand for electricity and how it varies, as well as irrigated agriculture's impact on their local economies. This information will provide a basis for determining if the discount can be targeted to specific irrigation loads. This effort may be coordinated with BPA's regional marketing program which is currently being developed.

2. Low Density Discount

Issue 1

Should eligibility for the Low Density Discount (LDD) include an average retail rate test?

Evaluation of Positions

The purpose of the LDD is to provide a rate discount to those utilities whose retail rates might suffer adverse impacts due to low system densities. In the summer of 1986, BPA conducted a public process to review the LDD. During this review process, several modifications to the existing LDD were proposed by interested parties and by BPA. One modification was the addition of an average retail rate test to the LDD eligibility criteria. This test would exclude from LDD eligibility any utility whose average retail power rate is less than the average BPA Priority Firm rate, plus 10 percent. The rationale behind the test is that if a utility cannot meet this criterion then it is not suffering adverse impacts on its retail rates due to a low system density that the LDD is intended to mitigate. Roghair/Margeson, BPA, E-BPA-27, 13-14. BPA proposed to adopt the average retail rate test in this proceeding.

PGP opposes an average retail rate test to determine eligibility for the LDD. PGP notes that application of this rate test would eliminate Grant County PUD, a PGP member utility, from its previous eligibility for a 3 percent LDD. Garman et al., PGP, E-PG-02, 13. PGP argues that an average retail rate which falls below BPA's PF rate plus 10 percent does not necessarily mean that a utility does not suffer adverse impact due to low system densities and, therefore, such a rate test is not the appropriate measure of adverse impact. Exceptions, PGP, R-PG-01, 11-12. PGP is concerned in a broader sense that this change in LDD may set a precedent for BPA rate decisions which would discriminate against relatively lower-cost utilities'

systems. Initial Brief, PGP, B-PG-01, 11. PGP states that the retail rate test is "an attempted incursion into the sacred territory" of utility retail ratemaking prerogatives. Id.

The purpose of the LDD is clearly set forth in section 7(d)(1) of the Northwest Power Act. Section 7(d)(1) provides that "[i]n order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers." 16 U.S.C. §839e(d)(1). Two pertinent points emerge from this language. First, the low density discount is not all-inclusive. Rather, it vests the Administrator with discretion to apply the discount "to the extent appropriate." Second, the discount is intended to "avoid adverse impacts on retail rates" caused by a utility's low system density. This consideration of retail rates is specifically addressed in the Act and does not represent an incursion into utility retail ratemaking prerogatives.

In this case, there is no dispute that Grant County PUD has a low system density. However, there is also no dispute that Grant is marketing retail power at prices below BPA's average Priority Firm Power rate. Grant County PUD is therefore not suffering adverse impacts as a result of its low system density which justify rate relief. It is appropriate for the Administrator to exercise his discretion to exclude from LDD eligibility all customers in this category.

Contrary to the suggestion of the PGP, the proposed retail power rate test does not single out Grant County PUD. It is applicable to all utilities on an equal basis. It neither discriminates against any particular customer nor transgresses any sacred bounds of utility ratemaking. It simply carries out the express purpose of section 7(d)(1).

Decision

The average retail rate test is an appropriate mechanism to satisfy the language and intent of section 7(d)(1) of the Northwest Power Act.

Issue 2

Should the LDD remain in effect and unchanged for a 5-year period?

Evaluation of Positions and Decision

PNGC supports BPA's proposed changes to the LDD, with the exception that PNGC urges BPA to lock the LDD eligibility criteria and the discount levels in place for a 5-year period to provide rate stability for customer utilities. Kitchen, PNGC, E-PN-01, 2; Exceptions, PNGC, R-PN-01, 10. Blachly-Lane Coop also proposes that the LDD be set for a minimum of 5 years from October 1, 1987. Blachly-Lane Coop, WP-87-7255.

BPA has concluded that the LDD should be continued for 5 more years. Roghair/Margeson, BPA, E-BPA-27, 10-11. However, in an effort to maintain

flexibility, the LDD criteria will not be locked in place for 5 years. Rather, BPA intends to propose the LDD in each subsequent Priority Firm Power rate schedule and to modify the LDD if necessary. After 5 years, BPA intends to conduct a review of the history, eligibility criteria, and methodology for the LDD.

3. Availability Charge

Issue

Should the PF-87 and NR-87 rates include an Availability Charge?

Evaluation of Positions

BPA proposes to continue the availability charge in the NR-87 and PF-87 rate schedules. The availability charge is an energy billing factor for computed requirements customers. The purpose of the availability charge is to compensate BPA for standing ready to serve such customers' power requirements. In particular, when these utilities choose to displace BPA power with either their own generation or other purchase power alternatives, BPA then may be forced to spill the displaced power or sell it as nonfirm energy, often at a price lower than its firm power price. The availability charge stabilizes BPA revenues by sharing the revenue loss due to this displacement between BPA and the displacing customer. 1985 Rates ROD, WP-85-A-02, 210.

PGP contends that the availability charge fails to consider the effect over the long term and therefore makes rational planning by BPA customers difficult. Hardy et al., PGP, E-PG-01, 4-5. PGP asserts that the revenues BPA receives from the charge are not significant to BPA. Garman et al., PGP, E-PG-02, 12-13. On the other hand, PGP contends that the annual $6 million BPA has received from the charge has caused the utilities to waste energy. Id., 12. Despite several data requests from BPA on these assertions, PGP provided little new evidence to support or document its position. After extensive review, BPA stands on the evidence and analysis performed in 1985, which is still valid. 1985 ROD, WP-85-A-02, 209-212.

In its Brief On Exceptions, PGP states that it is "incredulous" that BPA has given such "short shrift" in the Draft ROD to the PGP arguments regarding the availability charge. Exceptions, PGP, R-PG-01, 12. BPA regrets that PGP has this perception. It is not BPA's intent to diminish the importance of the availability charge or the issues regarding the charge raised by the PGP. The point, however, as stated above, is that the PGP has not raised any persuasive new arguments in this proceeding and all other arguments were fully addressed in the 1985 rate proceeding. For this reason, BPA adopts and does not depart from its stated position in the 1985 ROD, WP-85-A-02, 209-212.

PGP states that if BPA moves closer to the Northwest Parties' position on nonfirm rate design, i.e., a market-based rate which will recover costs, "it will be comparatively less attractive for the PGP utilities to use their nonfirm energy in their own system." Initial Brief, PGP, B-PG-01, 7. PGP also

contends that BPA's NF rate has been kept "artificially low." Exceptions, PGP, R-PG-01, 12-13. This statement implies that the higher the nonfirm energy price, the greater the incentive utilities will have to sell their nonfirm energy rather than use it on their own systems to displace BPA purchases. While this statement may be true, it suggests that BPA can control the price of nonfirm energy, which in turn will control displacement. This argument ignores the numerous market influences on the price of nonfirm energy. These influences in recent years have caused the actual price received for nonfirm energy to be well below BPA's cost-based rate. Refer to ROD Chapter VIII for discussion of the NF rate.

Decision

It is appropriate to retain the availability charge due to the costs incurred by BPA to stand ready to serve its customers. PGP has raised no new arguments against adoption of the charge in this rate case. BPA supports and adopts the rationale from the 1985 rate proceeding. 1985 Rates ROD, WP-85-A-02, 209-212.

4. Unauthorized Increase Charge

Issue

Should BPA assess an unauthorized increase charge on offpeak loads?

Evaluation of Positions and Decision

Gilmore Steel Corporation proposes that BPA not apply the unauthorized increase charge during offpeak hours. Gilmore Steel argues that, in a time of surplus, BPA's policy of applying the unauthorized increase charge to offpeak loads is counterproductive to BPA's interest. Gilmore Steel Corporation, WP-87-8422.

In the 1983 Record of Decision, BPA concluded that the unauthorized increase charge "is a penalty for a violation of the service conditions agreed to by both BPA and the customer . . . . It is entirely appropriate for the rate to apply to all load/resource periods since the purpose of the charge is to discourage customers from scheduling more power (on an hourly or daily basis) than was originally requested on a monthly basis under the contracts." 1983 Rates ROD, WP-83-A-02, 188.

In 1985, BPA extended the unauthorized increase charge to offpeak periods for the following reason: "BPA's operations are guided in part by DSI Operating levels, which are made known to BPA in advance of actual operations. Operating levels may be designated for the Peak and Offpeak Periods separately. Problems resulting from unauthorized increase may occur during both Peak and Offpeak Periods. As there is no measurably perceived difference between Peak and Offpeak Periods in this regard, it is more appropriate for the unauthorized increase charge to apply to all hours." Melton, BPA, WP-85-E-BPA-36S, 5. Gilmore Steel has not raised any additional facts or presented other argument that compels BPA to reverse its 1985

decision. BPA will continue to apply the unauthorized increase charge during offpeak hours in its 1987 rates.

B. Priority Firm Power Rate (PF-87)

Issue 1

Should an Exchange Program Oversight Charge be adopted?

Evaluation of Positions

BPA proposed the Exchange Program Oversight Charge (EPOC) as a means of allocating approximately one-half the exchange program implementation costs to nondeeming utilities that have Residential Purchase and Sale Agreements (RPSA) and Exchange Transmission Credit Agreements (ETCA) with BPA. Meyer, BPA, TR 1698. The charge was proposed as a solution to the equity concern that subsidy recipients should begin paying at least a portion of the special administrative costs of a program that does not benefit any of BPA's other customers. Meyer, BPA, E-BPA-42, 6.

The DSIs were the only customer group to expressly support the concept of an EPOC. Schoenbeck, DSI, E-DS-03R, 24. However, the DSIs objected to a flat charge, arguing that BPA's dedication of oversight resources should be reasonably related to the amount of benefits claimed. Based on this, the DSIs proposed that the EPOC be a fixed percentage of the exchange benefits initially claimed by the exchanging utility. Id., 24.

WUTC makes two primary arguments against the EPOC. WUTC first argues that review costs should be viewed as an administrative cost of acquiring energy which should be borne by the purchaser. Initial Brief, WUTC, B-WU-01, 16. This argument ignores the primary function of the average system cost (ASC) program, which is to determine the appropriate level of exchange subsidy for exchanging utilities. ASC is a rate, and BPA determines the appropriate ASC rate. When utilities file rates with the state commissions and FERC, a filing fee is imposed. BPA believes it is similarly well within its authority to impose a filing fee or similar cost recovery mechanism.

WUTC next states that BPA's intervention activities in state rate cases have generated little value from the perspective of the WUTC. Initial Brief, WUTC, B-WU-01, 16. This position is unfortunate because it shows a lack of understanding and appreciation of BPA's ASC review responsibilities.

During the reconsultation process on the 1984 ASC Methodology, many of BPA's customers strongly urged BPA to exercise greater oversight responsibility in administering the exchange program. Exchange program costs, borne by BPA's ratepayers, were out of control, and BPA had a tenuous handle on the technical complexity of the exchanging utilities' filings. The Administrator thus committed himself to greater oversight responsibility, such as through participating in utility rate case interventions, while at the same time undertaking the responsibility to independently determine the reasonableness and appropriateness of exchanging utilities' Contract System

Costs and Contract System Load. 1984 ASC Methodology, Review Procedures §III.A and B.

In line with BPA's exchange program oversight responsibilities, BPA has intervened in numerous investor-owned utility state rate cases. BPA has done this to better understand the background and basis for the utilities' ASC filings and to afford BPA some lead time to the 210-day ASC review cycle. The information gathered by BPA in the state rate cases has enabled BPA to exercise its oversight review in a much more thorough and effective manner, thereby considerably lessening the suspicion, contentiousness, and abuses that occurred previously when BPA was largely dependent on the utility for information. For example, BPA's ASC review of the attrition allowance granted Pacific Power & Light Company in WUTC Case No. U-86-02 was greatly facilitated by the understanding BPA gained through its intervention in Pacific's state rate case.

The WUTC's Brief on Exceptions offers BPA the opportunity to work with the WUTC in developing "a mechanism which will allow BPA to fulfill its obligation at lower cost to BPA rate payers." Exceptions, WUTC, B-WU-02, 5. BPA is appreciative of this offer and intends to follow up on it. Efforts to reasonably reduce BPA's ASC administration costs are of continuing importance to the Administrator.

PNGC and WPAG oppose the EPOC. PNGC asserts that BPA intended the EPOC to protect nonexchanging preference customers from the effect of the exchange. Initial Brief, PNGC, B-PN-01, 6-7. PNGC further asserts that Congress explicitly established the 7(b)(2) rate test as the protection mechanism to ensure that preference customers pay no more for BPA power than they would have in the absence of the Northwest Power Act including the exchange. Id., 6-7. PNGC states that the triggering of the 7(b)(2) rate test in this case is evidence of its effectiveness in protecting preference customers. Kitchen, PNGC, E-PN-05, 4.

PNGC and WPAG also argue, on various bases, that the EPOC is inequitable to public utilities, violates provisions of the exchange contracts regarding audit costs, and is unsupported by any evidence that would rationally justify the charge based on experience. Initial Brief, PNGC, B-PN-01, 6-8; Kitchen, PNGC, E-PN-05, 3-8; Initial Brief, WPAG, B-WA-01, 39-40. Regarding the equity of BPA's proposal, those parties argue in particular that the EPOC would have a disproportionate effect on the smaller exchanging public utilities. Id. WPAG also argues that the charge is not subject to the ratemaking process because it is a fee for administrative services, not power. Initial Brief, WPAG, B-WA-01, 40.

WPAG and PNGC raise some legitimate concerns regarding the "equity" of BPA's EPOC proposal. The effect of BPA's proposal, if adopted, would be to impact disproportionately many public utility exchangers that receive relatively small benefits. On the other hand, the form of BPA's proposal was predicated in part on its experience that BPA has in the past had to devote an inordinate amount of time and resources to reviewing ASC filings of public utilities; public utility ratemaking and ASC filings have frequently lacked the rigor and precision of investor-owned utilities' ratemaking practices and

ASC filings. BPA has been legitimately concerned that it apply the ASC Methodology in an even-handed manner and not tailor the thoroughness of its reviews to the magnitude of benefits sought by a particular utility.

At the same time, BPA has been internally, and externally in conjunction with its customers, exploring ways to make exchange program oversight more efficient, streamlined, and less controversial. Possibilities include informational forums, proposals to lessen the scrutiny of filings involving few or, in the case of deemers, no benefits, and negotiations with customers to either terminate or suspend their participation in the exchange program. These efforts will not come to fruition prior to BPA's final rate proposal. As such, there is much uncertainty concerning what changes will occur in BPA's exchange program administration. Further, it is reasonable to assume that the public utilities' ASC filings will improve as they become more familiar with the requirements of the residential exchange program. In this uncertain environment, it is questionable whether experience should serve as a guide for designing an equitable EPOC.

Decision

Given the circumstances outlined above regarding BPA's evaluation of its oversight and the equity concerns raised by the public utility exchangers, BPA is withdrawing its proposal to implement an exchange program oversight charge. Given this decision, it is unnecessary to address the legal basis for the development of an EPOC through the ratesetting process.

Issue 2

Should BPA develop a Priority Firm Power rate category that is lower than other Priority Firm rates for adopters of the Model Conservation Standards?

Evaluation of Positions

The City of Tacoma adopted the Model Conservation Standards (MCS) because of significant financial savings to electricity ratepayers of the City. Fey, City of Tacoma, E-TU-01, 3. The City began enforcing MCS as part of its energy code on June 1, 1984. The City of Tacoma argues that other areas have not adopted the MCS and the Northwest Power Planning Council withdrew its recommendation to impose a surcharge on the power purchases of utilities that serve areas that have not adopted the Model Conservation Standards. Id.

The City of Tacoma believes that utilities such as themselves which have adopted the MCS deserve a lower rate because those utilities will have to pay for additional regional resources needed due to other areas in the region not participating in MCS. Fey, City of Tacoma, E-TU-01, 6.

Tacoma admits that they adopted MCS because of significant financial savings to their ratepayers. Fey, City of Tacoma, E-TU-01, 3. The savings are saved purchases from BPA. In addition, the City of Tacoma received additional financial incentives from BPA to become an early adopter. This financial incentive will be paid by other BPA customers. It is not

appropriate for BPA to extend an additional financial incentive in the form of a lower rate to early MCS adopters.

Decision

In its 1987 rates BPA does not include a separate Priority Firm Power rate category for adopters of the Model Conservation Standards.

C. Industrial Firm Power (IP-87) and Variable Industrial (VI-87) Rates

Issue

What first quartile service language should BPA adopt for IP-87 and VI-87 rate schedules?

Evaluation of Positions

BPA has proposed to make the IP-87 rate schedule language consistent with VI-87 contract language. Roghair/Margeson, BPA, E-BPA-27, 15. In the IP-85 rate schedule the quality of first quartile service was represented by a premium rate and a lower standard rate. In IP-87 a single base rate is proposed with a lower quality of service tied to a discount to that rate.

DSI testimony proposes to make VI-87 rate schedule language consistent with IP-87 rate schedule language. Schoenbeck, DSI, E-DS-02, 7. Eligibility criteria for a discount for quality of first quartile service in the VI-87 rate schedule were adopted prior to the completion of Variable Rate contracts. Relevant contract provisions by reference should be cited in the VI-87 rate schedule similar to the cite in the IP-87 rate schedule to eliminate any potential ambiguities.

Decision

BPA will reference relevant Variable Rate contract provisions for eligibility criteria for the discount for quality of first quartile service in the VI-87 rate schedule to be consistent with the IP-87 rate schedule and to remove any potential ambiguities.

D. Firm Capacity Rate (CF-87)

Issue

Should BPA increase the CF-87 rate to reflect the purchaser's ability to compete with BPA in the PSW nonfirm energy market?

Evaluation of Positions and Decision

BPA's CF-87 rate for firm capacity sales is developed in precisely the same manner as CF-85 (see BPA, E-BPA-06, 71-72). In jointly-sponsored testimony, APAC and the DSIs argue that BPA should include a load factoring

charge in the CF-87 rate. This additional charge would account for BPA's opportunity cost that arises when CF purchases are used to displace BPA nonfirm energy on the Southern Intertie. Wolverton/Schoenbeck, APAC/DSI, E-PA/DS-01, 10-12. While a capacity purchaser has some ability to compete with BPA in the nonfirm energy market, this ability is not unique to capacity sales. Metcalf/Schaller, BPA, E-BPA-57, 14. Moreover, APAC/DSI testimony does not demonstrate that this displacement occurs with enough frequency to be a significant problem. Determining when such displacement may occur is not an easy task. APAC/DSI is incorrect that the difference between the price BPA could obtain for onpeak energy and the price it could obtain for offpeak energy is transferred free of charge to capacity purchasers. Initial Brief, APAC/DSI, B-PA/DS-01, 8. The right to receive a specified amount of onpeak energy is precisely what the purchaser of firm capacity buys under the CF rate schedule. Schaller, BPA, WP-85-E-BPA-40, 1-2.

Decision

For existing contracts, both of which expire in 1991, BPA will not include additional charges in the CF-87 rate schedule beyond the continued application of the extended peak surcharges imposed in prior rate proceedings. No demonstration has been made that such displacement presents significant problems or is applicable to only CF sales.

E. New Resources Firm Power Rate (NR-87)

Issue

Should the NR-87 rate be linked to the PF-87 rate?

Evaluation of Positions

The NR-87 rate is a cost-based rate based on allocated surplus firm power costs for both capacity and energy. There is no provision for a link with PF-87. All sales under this rate schedule are forecasted to be offpeak sales. Therefore, no capacity costs have been allocated to NR-87. However, to establish a rate which would be applicable to any qualifying load, the NR-87 demand charge is based on surplus firm power allocated costs. BPA, E-BPA-06, 73.

Puget raises two issues with respect to the NR-87 rate. The first issue is the need for rate stability; the second issue is the need for the NR rate to reflect BPA's restriction rights on the delivery of the power, i.e., supply stability. Lauckhart, PSP&L, E-PS-02, 1-4. Puget proposes that linking the NR and PF rates would provide the necessary rate stability to the NR rate. Puget also proposes that the restriction rights issue could be addressed through a rate credit equal to the difference between the linked PF and NR rates, making the NR rate equal to the PF rate. Lauckhart, PSP&L, E-PS-02, 5. However, Puget offers little data or rationale to justify or support its position on the NR rate.

PPC argues that the level of the PF rate is not relevant to an IOUs'decision to purchase NR power. Drummond/Peters, PPC, E-PP-06, 2. Citing the Northwest Power Act, PPC states that the IOUs are not eligible to purchase PF power and therefore should not consider the PF rate as an available alternative. Drummond/Peters, PPC, E-PP-06, 1-2. This position is strongly supported by APAC. Wolverton, APAC, E-PA-02R, 4.

PGP also supports PPC, adding that there is no justification for Puget to propose such a rate credit. In "plain terms," PGP states, Puget wants to place new load on BPA but not pay the higher costs of the new resources required to serve the load. Helgeson/Opatrny, PGP, E-PG-06, 4.

WPAG argues that a "linkage of the NR and PF rates will expose BPA to additional revenue underrecoveries, and difficult interclass cost allocation questions. Further, it would reduce BPA's flexibility during times of financial stress." McGary et al., WPAG, E-WA-03, 4.

WUTC, while not specifically endorsing Puget's proposal, urges BPA to devise some means of achieving predictability for the NR rate. This predictability is necessary if BPA is to be successful in marketing energy to regulated utilities. Initial Brief, WUTC, B-WU-01, 11-13. WUTC suggests that NR rate instability is due to three conditions: first, the lack of price assurance; second, the 7-year notice required before placing load under the NR rate; and third, BPA's ability to restrict delivery after a 5-year notice. Initial Brief, WUTC, B-WU-01, 13.

BPA has become increasingly aware that the regional investor-owned utilities are seeking greater stability and predictability in their future power arrangements with BPA, and that they do not perceive that the NR rate meets these needs. In an effort to respond to these concerns, which are in part characterized by those expressed by WUTC and Puget, BPA has initiated an effort to broaden regional utility markets. The purpose of this effort is to determine more clearly the needs of regional utility customers and the products with which BPA could meet those needs. PSP&L, WWP, and MPC expressed their encouragement that BPA acknowledged their concerns and will continue efforts during the rate period to examine these concerns. Exceptions, PSP&L/MPC/WWP, R-PS/MP/WP-01, 13-14.

Decision

For the 1987 rate proposal, BPA will not link the NR and PF rates, but proposes to continue to calculate the NR-87 rate based on costs allocated to surplus firm power to achieve the goal of a cost-based rate. However, efforts will continue during the rate period to examine the concerns expressed by WUTC and Puget regarding the stability and predictability of the NR rate.

F. Surplus Firm Power Rates

1. Long-Term Surplus Firm Power Rate (SL-87)

BPA's proposed SL-87 rate schedule will be available for the long-term purchase of surplus firm power. Contract terms may be as long as 20 years, but sales under this rate schedule cannot obligate BPA to acquire resources to extend the energy sale beyond the current energy surplus. The amount of power that may be sold under this rate schedule is limited to 1350 megawatts of capacity and 725 average megawatts of energy.

The SL-87 rate schedule allows a negotiated rate that may be unique to each contract. Forecasted revenue associated with this negotiated rate must fall, over the life of the contract, within a floor and ceiling. The floor is the present value of the revenue from the contract sale obtained by applying a Floor projection for firm power and firm capacity sales. The Floor projection for firm power sales is, in each year, the greater of BPA's forecasted Priority Firm Power (PF) rate or the forecasted opportunity cost of surplus firm power. For capacity sales, the Floor projection is the average PF demand charge.

Similarly, the ceiling is the present value of the revenue from the contract sale assuming a Ceiling projection. For firm power sales, the Ceiling projection is the fully allocated cost of BPA's highest cost resource. For firm capacity sales, the Ceiling projection is the demand component of BPA's highest cost resource.

On or about August 1, BPA will provide an opportunity for public comment on technical matters pertinent to BPA's projected SL-87 floor and ceiling. By October 1, following the close of public comment, BPA will publish any changes in its forecasted values, which will then be applicable for 1 year. Any negotiated SL contract executed within the 1-year period will be compared with the then applicable forecasted floor and ceiling to determine the ability of the negotiated rate to qualify under the SL-87 rate schedule.

Issue 1

Do the SL-87 rates take proper account of the risk of revenue underrecovery associated with long-term sales?

Evaluation of Positions

BPA's proposed SL-87 rate schedule is available for the duration of BPA's current surplus. Metcalf/Schaller, BPA, E-BPA-57, 2. Long-term availability of this rate schedule is proposed for two reasons. First, the size of BPA's firm surplus has increased in recent years, and BPA has had difficulty selling it at fully allocated cost. Metcalf/Schaller, BPA, E-BPA-26, 2. Recent declines in gas and oil prices have reduced substantially BPA's short term prices for sales of surplus firm power and have reduced the attractiveness of long-term contractual sales. Id., 2. Second, PNW and PSW utilities require some assurance of rate stability over time if they are to enter into long-term

contractual agreements with BPA. Id., 8. The SL-87 rate schedule seeks to combine these two goals of providing long-term rate stability and an enhanced ability to recover BPA's total costs. Id., 1-2.

FERC has expressed concern that revenue underrecoveries may occur in the later years of a long-term transaction and that these underrecoveries may become significant with an accumulation of contracts. Metcalf/Schaller, BPA, E-BPA-57, 5. PPC argues that revenue underrecoveries from the proposed SL-87 rate are likely to cause BPA to miss its scheduled payments to the U.S. Treasury. Drummond/Peters, PPC, E-PP-01, 5.

BPA disagrees that the SL-87 rate will cause BPA to miss its scheduled Treasury payments. BPA is required continually to review the adequacy of its overall rates to meet its total revenue requirement. BPA will continue to adjust its rates as necessary to ensure that its total revenue needs are met. Metcalf/Schaller, BPA, E-BPA-26, 8. Should underrecoveries occur due to the SL-87 rate, BPA will allocate them back to its other customers, just as surplus open market underrecoveries are currently reallocated in this rate case. Metcalf/Schaller, BPA, E-BPA-57, 8-9.

BPA initially proposed that the SL-87 rate schedule would be available for up to 20 years. Metcalf/Schaller, BPA, E-BPA-26, 4. PPC argued that BPA should not acquire new resources to serve these loads unless the costs of the resources could be fully recovered from these sales. Drummond/Peters, PPC, E-PP-01, 2. WPAG asserted that the SL-87 rate should be strictly limited in duration to the period of BPA's surplus. Without this limitation, according to these parties, BPA's regional customers would risk paying higher rates in the future to serve regional load growth. Higher rates would result from the need to build additional resources caused by the unavailability of Federal power sold on a long-term basis on the export market. McGary et al., WPAG, E-WA-01, 13-14.

To address this concern, BPA revised its SL-87 rate proposal so that the rate schedule would apply only to sales that do not require BPA to sell energy beyond the duration of the current surplus. Sales beyond this period may convert to a capacity sale or capacity-energy exchange, or the contract may terminate. Metcalf/Schaller, BPA, E-BPA-57, 4. This provision is fully acceptable to WPAG. McGary et al., WPAG, E-WA-04, 2. PPC, on the other hand, while endorsing the appropriateness of such a condition, objects that BPA has not stated unequivocably that contracts will in fact be converted. Drummond/Peters, PPC, E-PP-01, 2.

PPC's objection is unwarranted. BPA has specifically limited SL-87 to sales that impose no energy obligation on BPA beyond the duration of the surplus. This limitation is stated unequivocably in the rate schedule, which will be part of a contract as an exhibit. Metcalf/Schaller, BPA, E-BPA-57, Attachment 1, 1. Specific provisions for conversion, whether to a capacity sale, exchange, or contract termination, are contractual matters for negotiation between the parties. Such provisions are not rate matters and do not belong in a rate schedule. Metcalf/Schaller, BPA, E-BPA-57, 5.

Second, BPA has further restricted sales under the SL-87 rate schedule to a maximum of 1350 megawatts of surplus firm capacity and 725 average megawatts of surplus firm energy. Metcalf/Schaller, BPA, E-BPA-57, 5. Purchases under this rate schedule will be strictly limited to minimize the risk of incurring revenue shortfalls over time. A sale of the total amount of power available under this rate schedule represents less than 7 percent of BPA's total demand for firm power. Metcalf/Schaller, BPA, E-BPA-57, 5. Thus, any revenue underrecoveries that may occur under this schedule will not become significant through accumulation.

Decision

BPA's proposed SL-87 rate schedule accounts for the risks associated with long-term sales. These risks are minimized by limiting the amount of sales that can be made and by limiting energy sales to the current surplus.

Issue 2

Is the SL-87 rate schedule a better alternative for sales of BPA's surplus firm power than the continued reliance on the spot market?

Evaluation of Positions

BPA's SL-87 rate schedule permits a range of rates. Projected revenue from these rates over the entire contract period must lie within a floor and ceiling. The minimum revenue requirement is calculated by means of a Floor projection, which is the greater of BPA's forecasted opportunity cost of power in the spot market or the PF rate. Metcalf/Schaller, BPA, E-BPA-57, 12.

PPC objects to BPA's proposal, saying that the allowable range of rates under the SL-87 rate schedule permits surplus firm power rates to fall below the PF rate for a period of years. Drummond/Peters, PPC, E-PP-09, 3. PPC argues that too many uncertainties exist for BPA to conclude that the SL-87 rate is a better alternative than the spot market for BPA's existing customers. Uncertainties regarding repayment reform, BPA's choice of discount rates in calculating the floor, and the relative escalation of BPA's PF and SP rates over time make BPA's ability to recover costs with SL-87 highly suspect. Id., 4. PPC claims that BPA has not provided an analysis demonstrating that long term SL-87 sales will provide more revenue than the spot market. Exceptions, PPC, R-PP-01, 28. BPA disagrees that the spot market is a better alternative than the SL-87 rate on a forecasted basis. The SL-87 rate schedule is specifically designed to equal or exceed both the PF rate and the spot market rate over the contract period. Metcalf/Schaller, BPA, E-BPA-57, 2. In fact, the required demonstration that a negotiated contract rate falls between the Floor and Ceiling projections is precisely the study that PPC claims BPA has not conducted.

The SL-87 rate schedule will improve BPA's ability to recover its surplus power costs and repay Treasury for three primary reasons. First, long term sales allow purchasers to avoid the fixed cost of resources rather than just the variable costs as with spot market sales. Thus, purchasers are willing to

pay higher prices. Second, long term sales have a greater potential than spot market sales to delay the development of new nondispatchable resources, such as QF's. This will increase the total market for BPA's firm and nonfirm surplus power. Finally, SL-87 sales will diversify BPA's revenue sources and reduce its risks. Currently, over 16 percent of BPA's revenue is assumed to come from spot market sales. BPA, E-BPA-32A, 289. In addition, as the PPC itself points out, low gas prices (which lead to low spot market prices) could conceivably lead to erosion in BPA requirements sale markets. The SL-87 rate is needed to reduce the risks to BPA associated with the spot market and low fuel prices.

The potential for underrecoveries caused by BPA's reliance on the spot market for surplus firm power sales is amply demonstrated in this rate case. Metcalf/Schaller, BPA, E-BPA-57, 8. In BPA's supplemental rate proposal, BPA's PF customers are allocated over $233 million of underrecovered surplus firm power costs during the FY 1988-FY 1989 test period. BPA, E-BPA-32A, 239. This reflects the fact that most of BPA's total firm surplus of 1343 average megawatts is projected to be sold on the spot market at less than fully allocated cost. BPA, E-BPA-32A, 32. BPA expects that long-term contracts for the sale of surplus power will relieve this existing pressure on BPA's current rates. This will actually reduce the long-term risk of revenue shortfalls from SL-87 by stabilizing BPA's other loads.

PPC is correct that BPA's forecasts project spot market prices that approach its fully-allocated cost of surplus firm in the long run. PPC is also correct that actual SL-87 rates may fall below the PF rate and spot market prices. Opening Brief, PPC, B-PP-01, 25-27. That there are risks inherent in the SL-87 rate schedule is apparent enough. However, these risks are much smaller than the continued reliance on the uncertainties of the spot market.

On an actual basis, for example, spot market prices conceivably may exceed the contract SL-87 rate. However, if spot market prices are high, they are likely to have a positive influence on BPA's total revenue. Revenue shortfalls are unlikely in these circumstances. BPA nonfirm energy and additional unsold surplus firm power, including any created by PF and DSI load underruns, will be sold in this favorable spot market. Metcalf/Schaller, BPA, E-BPA-57, 9. The increased revenue from such sales will reduce preference customers' rates.

If BPA is having difficulty setting rates to repay the Treasury, it is far more likely that the spot market is depressed. In such a situation, SL-87 revenue, even if below fully allocated costs, will be much greater than the spot market alternative. Id., 10. Thus, sales under SL-87 will decrease, not increase, the possibility that BPA will be unable to make its Treasury payments. Id. PPC maintains that BPA's customers' load may be too elastic to absorb underrecovered costs in the future. Drummond/Peters, PPc, E-PP-04, 1, 15-18. PPC alleges that preference customers have supply options other than BPA. Peters, PPC, E-PP-04, 2. If preference customers do indeed have such options, many of these same options are available to BPA's potential surplus power customers. Metcalf/Schaller, BPA, E-BPA-57, 8. Surplus power rates that are fixed at too high a level to be marketable serve neither the

potential purchaser nor the preference customer that PPC wishes to protect. Metcalf/Schaller, BPA, E-BPA-57, 8. If surplus power rates are not commercially attractive, the surplus will not be sold. Rather, unsold surplus will continue to be paid for in large part by preference customers.

Long-term sales under the SL-87 rate schedule maximize BPA's potential for recovering the costs of surplus firm power relative to the alternative of remaining in the spot market. Sales under this rate schedule will reduce the underrecovery of costs allocated to surplus power in future rates and correspondingly will reduce the amount of underrecovered costs reallocated to preference customers.

Finally, BPA does not intend simply to market SL-87 at the projected floor. BPA's continuing goal is to sell its surplus firm power at fully allocated cost. Id. Rate and escalation formulae will be examined carefully by BPA negotiators along with the costs and benefits of other contract features. Id.

Decision

The SL-87 rate schedule is a better alternative for sales of BPA's surplus firm power than continued reliance on the spot market. Sales under SL-87 will reduce the projected value of future PF rates and the probability of missing Treasury payments.

Issue 3

Should SL-87 be available beyond the terms of the Power Sales Contract and Coordination Agreement?

Evaluation of Positions

BPA's initially proposed SL-87 rate schedule offered up to a 20-year term for long-term contracts executed during the rate period. Metcalf/Schaller, BPA, E-BPA-26, 4.

WPAG asserts that permitting surplus firm power sales to extend beyond the termination date of BPA's Power Sales Contract is improper. WPAG suggests that such purchases of surplus power could have a greater claim to BPA's firm power than future regional requirements purchases. McGary et al., WPAG, E-WA-01, 12. In addition, WPAG argues that renewal of the Coordination Agreement is uncertain, and therefore BPA's ability to fulfill its obligations to deliver surplus power beyond the termination date of the Coordination Agreement is questionable. WPAG concludes that it is not prudent business practice to assume an export obligation beyond this date. McGary et al., WPAG, E-WA-01, 12.

BPA has revised its SL-87 rate proposal to address WPAG's concerns. First, the SL-87 rate schedule is available only during the period BPA is in surplus. Second, the SL-87 rate will not be available for contracts that

obligate BPA to acquire energy resources to support the sale. Metcalf/ Schaller, BPA, E-BPA-57, 2, 4. These revisions essentially eliminate WPAG's concern that BPA could obligate itself to serve a surplus power purchaser at the expense of its regional preference customers. Metcalf/Schaller, BPA, E-BPA-57, 4. WPAG endorsed these revisions in its rebuttal testimony. McGary et al., WPAG, E-WA-04, 2.

Decision

Contracts using the SL-87 rate schedule may extend beyond the terms of the Power Sales Contract and Coordination Agreement, but the SL-87 rate will be available only for sales that do not obligate BPA to acquire energy resources to support the sale.

Issue 4

Will the long-term availability of the SL-87 rate schedule result in higher Priority Firm rates?

Evaluation of Positions

WPAG asserts that BPA is moving toward rates that are either capped or have a formula escalation for the long term. PPC and WPAG argue that this reduced flexibility will force BPA to look to the PF customer class to recover all revenue deficiencies. McGary et al., WPAG, WA-01, 3-4; Peters, PPC, E-PP-04, 15. PPC asserts that PF customers have only a limited ability to protect BPA's revenues. Drummond/Peters, PPC, E-PP-01, 4; Peters, PPC, E-PP-04, 1. WPAG adds that BPA should retain the flexibility to adjust surplus power rates by restricting the duration of SL-87 to the rate period. McGary et al., WPAG, E-WA-01, 16.

PPC and WPAG's concerns reflect a fundamental misconception about BPA's alternatives for selling its current surplus. For PPC and WPAG to be correct, they must assume that the surplus can be sold under fully adjustable rates at fully allocated cost. Only under this circumstance can BPA be certain that a surplus sale will not result in revenue underrecoveries to be reallocated to other customer classes. Metcalf/Schaller, BPA, E-BPA-57, 7. However, it has not been the case historically that BPA can sell its surplus at fully allocated cost. Metcalf/Schaller, BPA, E-BPA-26, 2. The SL-87 rate cannot add to the underrecovery of surplus firm sales that already exists, since the SL-87 floor is based on alternative spot market sales. The PPC is concerned that negotiated SL-87 rates will not allow BPA to recover the costs of repayment reform. This would be a valid argument only if there were reason to believe that repayment reform would increase BPA's ability to recover revenue in the spot market. Clearly, that is not the case.

The flexibility the PPC seeks to maintain does not currently exist. BPA cannot allocate revenue deficiencies to power that is sold below cost on the spot market. Instead, BPA's flexibility will increase with SL-87 sales by diversifying the type and duration of potential surplus power transactions.

Sales under this rate schedule will ease rate pressures on its existing preference customer load and help to prevent load erosion and further rate increases due to soft markets. Metcalf/Schaller, BPA, E-BPA-57, 7. PPC itself acknowledges the importance to preference customers of keeping near-term PF rates low. Peters, PPC, E-PP-04, 16-18.

WPAG specifically asserts that the SL-87 rates will cause regional preference customers to bear a disproportionate share of residential exchange costs. WPAG is concerned that IOU resource acquisitions in the early 1990s will drive up exchange costs. Such cost increases will cause the allocated costs of surplus firm power to increase at a faster rate than Priority Firm rates. To the extent SL-87 sales do not capture these costs in its escalation formulae, a revenue deficit is created that must be borne by BPA's general requirements customers. McGary et al., WPAG, E-WA-01, 15.

Once again, WPAG assumes that BPA's alternative to the SL-87 rate schedule is fully adjustable surplus power rates at fully allocated cost. Only under this circumstance can unexpected exchange cost increases be recovered by the surplus power purchaser. Except for this circumstance, sales at the SL-87 rate cannot contribute to higher Priority Firm rates.

Nor are the risks of increased exchange costs as pressing as WPAG argues. First, BPA's forecasts already account for assumed costs of IOU resource acquisitions beginning in the early 1990s, and the resulting increase in exchange costs is factored into BPA's projected rates. Metcalf/Schaller, BPA, E-BPA-57, 10. Second, the average system cost methodology allows BPA to reject any new resource costs from an average system cost calculation if BPA determines that a resource is not cost-effective. Metcalf/Schaller, BPA, E-BPA-57, 10-11. Third, the 7(b)(2) test provides preference customers with protection against unrecovered exchange costs. Fourth, the SL-87 rate reduces the likelihood of higher exchange costs by making BPA purchases an attractive alternative to IOU resource acquisitions. Metcalf/Schaller, BPA, E-BPA-57, 11. Together, these factors should minimize the risk to public agency customers of shouldering revenue deficits caused by unexpected cost increases from the residential exchange.

Similarly, PPC argues that an IOU purchaser of firm displacement power under SL-87 may pass any losses it may incur from this transaction through the residential exchange. This would result in higher BPA exchange costs and subsidies being paid by those who incur the costs of the residential exchange. Drummond/Peters, PPC, E-PP-01, 15. Applying WPAG's logic, regional preference customers would receive a disproportionate share of these costs. Drummond/Peters, PPC, E-PP-01, 15.

This issue also was raised by PPC in the FD-85 rate proceeding. Opening Brief, PPC, FD-85-B-PP-01, 5-9. BPA concluded then that determinations of average system cost are not properly made in BPA wholesale power ratemaking proceedings. FD ROD, FD-85-A-02, 67-68. BPA's decision remains unchanged. This issue has been discussed at length in public proceedings pertinent to BPA's FD contract principles. Comments by PPC are more appropriately addressed in that forum.

Decision

The SL-87 rate schedule increases BPA's ratemaking flexibility by diversifying BPA's firm customer base and providing a margin of rate relief for BPA's existing load, in particular its preference customer load.

Issue 5

Are BPA's Capacity-Energy Exchange Contracts and Canadian Entitlement Allocation Agreements examples of BPA's ability to execute long-term contracts having fixed rates that recover costs?

Evaluation of Positions

PPC and WPAG object to the term of the SL-87 rate, arguing that BPA's inability to recover costs from negotiated rates fixed by contract is historically demonstrable. WPAG and PPC argue that long-term rate commitments have repeatedly produced revenue deficits, citing BPA's capacity-energy exchange contracts and the sale of entitlement and supplemental capacity as examples of BPA's ineffectiveness. McGary et al., WPAG, E-WA-01, 15; Drummond/Peters, PPC, E-PP-01, 5, Attachment 1.

BPA disagrees that these two sets of contracts illustrate BPA's failure in negotiating long-term arrangements that benefit BPA's regional customers. Metcalf/Schaller, BPA, E-BPA-57, 13. PPC and WPAG's allegations demonstrate only a misunderstanding of the total economics of these contracts. Id., 11. While PPC and WPAG are correct that a revenue underrecovery from entitlement and supplemental capacity exists when viewed in isolation, this "underrecovery" is far outweighed by the benefit to the Pacific Northwest region from the full set of agreements that implemented the Columbia River Treaty. The Canadian Entitlement Exchange Agreement, which contains the provisions for entitlement and supplemental capacity, is one of these agreements. Without this agreement and the provisions it contains, the Columbia River Treaty could not have been effectuated. Id., 12-13.

As for the capacity-energy exchange agreements, the alleged underrecovery of costs resulting from these agreements is illusory. Id., 13. Under these agreements, peak energy is exchanged for offpeak energy and paid for, not with dollars, but with additional offpeak energy returns (Exchange Energy). Since no dollars are received in an exchange transaction, an artificial revenue "deficiency" is assigned to the beneficiaries of these agreements. Id., 14. These beneficiaries are primarily BPA's preference customers, who receive inexpensive firm power in the form of this Exchange Energy payment, which is added to BPA's Federal base system resources. Id.

Decision

BPA's capacity-energy exchange contracts and Canadian Entitlement Allocation Agreements demonstrate BPA's past success in negotiating long-term contracts that provide significant benefits to regional preference customers.

Issue 6

Should firm displacement transactions preclude a PNW purchaser from reshaping its firm resources and sending a higher grade of power to a Pacific Southwest purchaser?

Evaluation of Positions

BPA initially proposed a Firm Displacement (FD) rate that would permit a Northwest purchaser to displace its own generation with BPA's surplus firm power and then sell its displaced generation outside the region. Metcalf/Schaller, BPA, E-BPA-26, 4. In subsequent testimony, BPA incorporated the FD rate into the SL-87 rate schedule, under which firm displacement transactions may be negotiated. Metcalf/Schaller, BPA, E-BPA-57, 4.

PPC opposes the implementation of a firm displacement transaction because it exposes BPA to financial risk. Specifically, PPC argues that a PNW purchaser of firm displacement power may buy one grade of power from BPA, gain access to the intertie, and then use its own resources to sell a higher grade of power to the Southwest. Drummond/Peters, PPC, E-PP-01, 14. By a higher grade of power, PPC means the reshaping of energy purchases to different seasons or times of day and trading energy for capacity. PPC fears that BPA will suffer a loss of revenue, because it has displaced potential sales of nonfirm energy or surplus power on the Southern Intertie. Drummond/Peters, PPC, E-PP-01, 15.

This argument echoes PPC's concern expressed in the FD-85 rate proceeding. Wolverton/Drummond, PPC, FD-85-E-PP-01, 20-22; Opening Brief, PPC, FD-85-B-PP-01, 18-19. BPA responded then that the issue of shaping FD power is not a rate matter but a matter for contract negotiation. FD ROD, FD-85-A-02, 56. PPC has not raised any additional facts or made any different argument in this case that would cause BPA to depart from that decision. The issue of the shaping of firm displacement power is addressed in BPA's FD Contract Principles. Metcalf/Schaller, BPA, E-BPA-57, 11.

Decision

Shaping BPA's sale of firm displacement power to coincide with the utility's displaced resources is a matter for contract negotiation and will not be addressed in rate schedules.

Issue 7

Are SL-87 sales to the Pacific Northwest IOUs consistent with section 7(f) of the Northwest Power Act?

Evaluation of Positions

BPA's SL-87 rate schedule is available for the sale of surplus firm power and firm displacement power to private and public utilities both inside and outside the Pacific Northwest. Metcalf/Schaller, BPA, E-BPA-26, 8. PPC

argues that the ability of an IOU to negotiate a sale below the NR rate violates section 7(f) of the Northwest Power Act. Drummond/Peters, PPC, E-PP-09, 5; E-PP-01, 8; Initial Brief, B-PP-01, 30, n. 29; Brief on Exception, PPC, R-PP-01, 29. WPAG makes a related argument, alleging that SL-87 rates to IOUs below the NR rate will compromise BPA's "operational integrity" and effectively end any possibility of future NR sales. McGary et al., WPAG, E-WA-01, 17.

PPC's argument that SL-87 violates section 7(f) of the Northwest Power Act rests solely on a citation to Northwest Power Act legislative history for the proposition that the 7(b) rate is to be the Administrator's lowest firm power rate. Initial Brief, B-PP-01, 30, n. 29. Resort to legislative history, however, is justified only when there is ambiguity in the statutory language. Legislative history cannot be relied on to create an ambiguity. In this case the statute is clear: neither section 7(b) nor section 7(f) states that section 7(b) rates are to be the lowest firm power rates established by the Administrator. In any event, the SL-87 rate is designed to be at least as high as the Priority Firm rate, since the floor projection under SL-87 is the greater of BPA's projected opportunity cost for firm power or the projected Priority Firm rate.

WPAG's argument that sales to IOUs at rates below the NR rate will impair BPA's operational integrity is unfounded. SL-87 is available only for contracts that do not obligate BPA to acquire energy resources to support the sale. BPA is thus selling only existing surplus firm power under this rate schedule. The rate shcedule cannot obligate BPA to acquire resources or serve IOU load growth.

BPA intends for any sales to regional Investor Owned Utilities under the SL-87 rate schedule to supplement, not replace, sales under the current power sales contracts at the New Resource Rate. At the time those utilities need to add resources to serve load growth, BPA believes that the New Resources Rate will be their most cost effective source of power. BPA is continuing to explore ways to improve the long term marketability of the New Resources Rate.

Decision

SL-87 sales to Northwest IOUs are consistent with section 7(f) of the Northwest Power Act.

Issue 8

Is the 7-day notification period insufficient notice for parties interested in providing written comments on the calculation of the SL-87 floor and ceiling projections?

Evaluation of Positions

BPA's proposed SL-87 rate schedule provides for an annual determination of forecasted PF rates, opportunity cost of surplus firm power and fully-allocated cost of BPA's highest cost resource for the succeeding 21-year period. These values will be used to determine the applicability of the SL-87

rate schedule for contracts having long-term surplus firm power rates. The initial determination of these values will be published each August 1, and interested parties will have 7 days to notify BPA of its interest in commenting on BPA's valuation. Metcalf/Schaller, BPA, E-BPA-57, Attachment A.

PG&E comments that 7 days is insufficient notification for utilities to enable them to decide whether to comment on BPA's floor and ceiling projections. PG&E, WP-87-7494, 8. While no other party or participant objected to the duration of the notification period, BPA agrees with PG&E that the notification period may be too short.

Decision

BPA will provide 14 days' notice to parties interested in commenting on BPA's proposed floor and ceiling projections.

2. Short Term Surplus Firm Power Rates (SP-87)

Issue 1

May SP-87 rates exceed BPA's average system cost?

Evaluation of Positions

BPA's proposed SP-87 rate contains a Contract rate that is designed to recover exchange resource and new resource costs. BPA, E-BPA-06, B39. The SP-87 rate may vary above or below the Contract rate, but it cannot exceed the fixed and variable costs of BPA's highest cost resource. BPA, E-BPA-06, B37. SCE argues that SP-87 rates should not exceed BPA's average system costs, because both nonfirm energy and firm power are produced by BPA's entire system. SCE, WP-87-7229, 29.

SCE appears to have three different objections to the SP-87 rate: (1) residential exchange costs should not be allocated to surplus firm power rates; (2) BPA should not have the flexibility to set these rates up to a maximum rate of the fixed and variable costs of BPA's most expensive resource, and (3) SP-87 should not permit rates higher than the average PNW firm power rate.

First, SCE is correct that surplus firm power is produced by BPA's entire system. However, while the size of the firm surplus is based on BPA's total system, the rate charged for the surplus is a function of the cost allocation requirements of the Northwest Power Act. The Act creates three resource pools: FBS, Exchange, and New Resource. The total size of these resources exceeds BPA's loads, leaving the costs of surplus exchange resources and new resources to be recovered in the spot market or under longer-term arrangements, or allocated to BPA's native firm power customers. In order to meet its obligations under section 7(a) of the Act, BPA will continue to strive to recover as much of the costs of its surplus power as possible through off system sales.

Congress provided for the circumstance that the application of individual section 7 rate directives could result in a situation where some costs would not be recovered. Congress expressly addressed the recovery of costs associated with an "inability to sell excess electric power" in section 7(g), 16 U.S.C. §839e(g), which allows BPA to "equitably allocate to power rates . . . all costs and benefits not otherwise allocated." Congress gave BPA the flexibility to recover unsold power costs from all rates, including surplus power rates such as SP-87 and SL-87.

Regarding SCE's second objection, it is appropriate for the SP-87 schedule to permit sales at rates as high as the fully allocated cost of BPA's highest cost resource. BPA's preference is to negotiate long-term sales of this surplus firm power. However, BPA will continue to sell surplus firm power in the spot market until longer-term sales can arranged. The spot market, however, necessarily imposes risks on both buyers and sellers. BPA risks making sales at prices less than the costs allocated to the power. Purchasers bear the risk that low spot market prices will eventually be offset by higher prices. Utilities with firm surplus typically attempt to sell their highest cost resource, and these sales are approved by regulators as being cost-based. Nothing in the Northwest Power Act precludes BPA from doing the same thing.

Further, section 7(g) of the Act directs BPA, when setting rates to recover the costs not recovered nor otherwise allocated, to do so "in accordance with generally accepted ratemaking principles." 16 U.S.C. §839e(g). It is standard industry practice for utilities seeking to sell surplus resources generally to sell their most expensive resources first. For example, the Western Systems Power Pool agreement, recently approved by FERC, allows participants to set prices up to the cost of the highest fully allocated cost resource of any participant, in this case, 245 mills/kWh. Pacific Gase and Electric Company, 38 FERC ¶61,242, 61,782, 61,808 (1987). BPA's surplus firm power rates allow BPA similar flexibility, in order to enhance BPA's ability to meet its financial obligations under section 7(a).

Third, SCE objects that the SP rate improperly treats California firm power purchasers differently from PNW firm power purchasers. SCE-7229, 28. SCE argues that the SP-87 rate should be comparable with the forecasted average rate charged BPA's PNW firm customers. Id., 29. This argument fails for several reasons. First, SCE overlooks the fact that California utilities are not the only utilities that purchase surplus firm power from BPA. BPA will use the same SP-87 rate for sales both within and without the Northwest. Further, SCE's argument that California firm power purchasers should be treated just like BPA's PNW public preference customers is inconsistent with the Northwest Power Act. Neither BPA's California firm power purchasers nor BPA's Northwest investor-owned utility firm power purchasers have the same legal standing under section 7(b) of the Northwest Power Act, 16 U.S.C. §839e(b) as BPA's native load public preference customers. This standing is entirely statutory and is not the result of any action, improper or otherwise, on the part of BPA.

Issue 2

Should spot market sales of surplus firm power be sold under the nonfirm rate schedule?

Evaluation of Positions

The SP-87 rate schedule is designed with sufficient flexibility to market surplus firm power at spot market prices. Metcalf/Schaller, BPA, E-BPA-26, 1. SCE argues that spot market sales, regardless of the firmness of the source of the energy, should be sold under BPA's nonfirm energy rate schedule. SCE, WP-87-7229, 28. SCE cites Fort Pierce Utilities Authority v. FERC, 730 F.2d 778 (D.C. Cir. 1984), for the proposition that hourly sales cannot be regarded as anything but nonfirm service. SCE, WP-87-7229, 28, n. 50.

Because this issue will be resolved by FERC in the upcoming section 7(k) hearing regarding BPA's 1985 nonfirm energy rates, BPA will not address it in depth here. Nevertheless, BPA believes that SCE's argument is without merit.

FERC Administrative Law Judge Miller's Initial Decision, 29 FERC ¶63,069 (1984), affirmed in almost all respects by the Commission in Opinion 250, U.S. Department of Energy, Bonneville Power Administration, 36 FERC ¶61,798 (1986), has already recognized the differences between the firm power and the nonfirm energy produced by BPA's system. Regardless of the time period over which these products are delivered, they are distinctly different. Hourly sales of surplus firm power are not effectively "nonfirm." The Court of Appeals' remand to FERC in Fort Pierce does nothing to change these facts.

Decision

Hourly sales of surplus firm power are not required to be made under the nonfirm energy rate schedules.

Issue 3

What surplus firm power rate schedules should BPA establish to assist BPA's regional consumer marketing program?

Evaluation of Positions

In its direct case, BPA briefly addressed consumer marketing, stating that a consumer marketing program is being developed and that the proposed SP-87 rate schedule would be available for sales under the program. Metcalf/Schaller, BPA, E-BPA-26, 3. The initially proposed SP-87 and NF-87 rate schedules also were worded so that they would not conflict with a consumer marketing program. BPA, E-BPA-06, B37 and B51; Metcalf/Schaller, BPA, E-BPA-26, 3; Diffely, BPA, E-BPA-49, 3.

Virtually all parties support the concept of consumer marketing. Exceptions, ICUA, R-IU-01, 4. However, some parties stress the need for BPA

to carefully set criteria to govern consumer marketing. Schoenbeck, DSI, E-DS-03R, 21-22; Emerald PUD, WP-87-7507.

Other parties are more critical of BPA's proposal. For instance, PNGC states that the proposed SP-87 rate schedule does not include the features needed to attract new industrial loads to BPA's service area. Kitchen, PNGC, E-PN-02, 6; Exceptions, PNGC, R-PN-01, 9. PPC states that "[s]ales under SP/SL-87 absolutely must not displace sale [sic] under PF-87 and NR-87 because BPA may be harmed by the firm load erosion." (Emphasis in original.) Drummond/Peters, PPC, E-PP-01, 8.

Foreseeing the need for a well-formulated approach to the needs of regional industries, two parties propose rate schedules to assist BPA's consumer marketing goals. PNGC proposes the IM-87 rate schedule to correct certain alleged "deficiencies" in the proposed SP-87 rate schedule. Kitchen, PNGC, E-PN-02, 1, 6. PNGC's IM-87 rate is supported by the comments of several participants: City of Ellensburg, WP-87-7248; Blachly-Lane County Coop Electric Association, WP-87-7255; Kootenai Electric Cooperative, Inc., WP-87-7222; Port of Benton, WP-87-7368; Wyoming Rural Electric Association, WP-87-7394; Tri-City Industrial Development Council, WP-87-7426; and City of Richland, WP-87-7512; and by ICUA. Initial Brief, ICUA, B-IU-01, 6-7; Oral Argument, ICUA, TR 3049.

Dow Corning Corporation proposes that BPA establish a Variable Industrial rate (similar to BPA's rate for the PNW aluminum smelters) tied to the price of silicon (VI(S)-87) for Dow's purchase of surplus firm power from BPA through the Springfield Utility Board. Moke, Dow, E-DC-01, 6-7; Initial Brief, Dow, B-DC-01, 4; Exceptions, Dow, R-DC-01, 2.

In response to these two proposals, Central Lincoln PUD, PGP, and City of Tacoma oppose facets of PNGC's IM-87 rate proposal. Central Lincoln PUD, WP-87-7207; Helgeson/Opatrny, PGP, E-PG-06, 1; Initial Brief, PGP, B-PG-01, 4; City of Tacoma, WP-87-7353. The DSIs, APAC, PGP, and City of Tacoma all are critical of Dow's rate proposal. Schoenbeck, DSI, E-DS-03R, 22; Wolverton, APAC, E-PA-02R, 1; Helgeson/Opatrny, PGP, E-PG-06, 1; Initial Brief, PGP, B-PG-01, 4; City of Tacoma, WP-87-7353.

PGP recognizes that before BPA adopts any specific incentive rate proposal it is important for BPA to clarify and document its market, objectives, policies, and criteria. Helgeson/Opatrny, PGP, E-PG-06, 5. BPA currently is undertaking these tasks in a forum apart from this rate case, that is addressing consumer marketing in the Pacific Northwest. In order to protect the integrity of that process, it is inappropriate to decide on the merits of either rate proposal or to prejudge the results of that forum by constraining BPA's consumer marketing program in the 1987 rate schedules. Diffely, BPA, E-BPA-49, 2-3. Until the consumer marketing program is designed and in place, establishing a rate for sales under the program would be inappropriate. Id.; Governor of Oregon, WP-87-7514.

With those objectives in mind, the proposed SP-87 rate schedule includes features that will allow it to be sufficiently flexible to be used effectively

as a market-based rate for BPA's consumer marketing program. Metcalf/Schaller, BPA, E-BPA-26, 3. The NF-87 schedule also is provided the flexibility to accommodate whatever consumer marketing program results from the program development process. BPA, E-BPA-06, B51.

Decision

BPA will not adopt special rates for consumer marketing in this rate proceeding, either for a specific marketing effort or for a specific customer. The proposed NF-87 and SP-87 rate schedules are designed to accommodate whatever marketing program results from BPA's consumer marketing program development.

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CHAPTER X

TRANSMISSION RATES

A. Introduction

The Transmission Rate Design Study (TRDS) is the basis for developing BPA's rates for wheeling service. The following is a brief description of the transmission rates subject to adjustment in this proceeding. The FPT-87.1 rate is available for firm wheeling on the Network segment pursuant to agreements allowing annual rate adjustments. The FPT-87.3 rate is available for the same service as FPT-87.1, but applies to agreements which provide for rate adjustment not more than once every 3 years. The IR-87 rate, a postage-stamp rate, also applies to firm wheeling on the Network, but without consideration of specific contract paths or distances. It consists of both a capacity and an energy component. The ET-87 rate is an energy-based rate available for nonfirm wheeling on the Network. The three intertie rates, IE-87, IN-87, and IS-87A, are available for nonfirm wheeling services on the Eastern, Northern, and Southern Interties, respectively.

For this rate proceeding, a Market Transmission rate (MT-87) was developed for transactions pursuant to the recently approved Western Systems Power Pool (WSPP) Agreement. In addition, the Southern Intertie rate schedule has been restructured into two components: the IS-87A rate for nonfirm wheeling and the IS-87B rate (in the initial proposal IS-87B1) for firm wheeling for firm power sales of Pacific Northwest scheduling utilities. 1/ The IS-87 rate schedule is applicable for south-to-north as well as north-to-south transactions.

Three additional wheeling rates are referenced in existing agreements and are not subject to adjustment in this general rate proceeding. These are the TGT-1, UFT-83, and UFT-2 rates. The TGT-1 and UFT-83 rates are effective through June 30, 1990. 39 FERC ¶61,078. The UFT-2 rate is applicable to existing agreements with PP&L (Contract No. 90049) and PGE (Contract No. 49110) and is scheduled to expire September 30, 1987. Id. BPA is requesting extension of UFT-2 through June 30, 1990.

B. Southern Intertie Nonfirm Transmission Rate (IS-87A)

BPA currently shares its nonfirm (hourly) use of the Federal portion of the Southern Intertie with non-Federal utilities via a formula allocation methodology. This methodology allocates hourly use of the Intertie based on the scheduling utilities' declared resources available for sale to California. BPA will apply the IS-87A rate to the monthly sum of kilowatthours scheduled (actual use), plus the monthly sum of kilowatthours

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1/ Between the Draft ROD and the Final ROD, the Administrator decided not to adopt the IS-87B2 rate. It was further decided that the IS-87B1 rate should be renamed the IS-87B rate. Therefore, all references to the IS-87B1 rate in earlier documents refer now to the IS-87B rate.

allocated but not scheduled. In other words, hourly Intertie space that is allocated, but not used, will be billed. Chang et al., BPA, E-BPA-48, 9. The amount of energy allocated but not used may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. BPA, E-BPA-07, 117. BPA may accept return allocations in other circumstances, at BPA's discretion. Griffin et al., BPA, E-BPA-30, 2; E-BPA-61, 3.

PP&L and PGE are the principal opponents of the IS-87A rate and object to billing based on allocation for several reasons. They allege that the rate will: (1) produce an expected overcollection of transmission costs; (2) produce an inequitable allocation of transmission costs between Federal and non-Federal use; (3) not account for all reasons beyond the control of Northwest utilities that may at times render nonfirm transmission allocations unusable; and (4) tend to reduce unreasonably the region's total nonfirm revenues by enhancing the bargaining position of California utilities. Initial Brief, PP&L/PGE, B-PL/GE-01, 58 and 59.

Issue 1

Will the IS-87A rate produce an expected overcollection of transmission costs?

Evaluation of Positions

PP&L contends that billing based on allocation rather than use will lead to an overcollection of transmission revenues because transmission revenue requirements are based on expected use rather then allocations. Brattebo, PP&L, E-IO-05, 2; Initial Brief, PP&L/PGE, B-PL/GE-01, 59. However, with implementation of this billing application, utilities should be discouraged from holding unused Intertie allocations. As a result, BPA expects that the Intertie allocation that is received and the actual energy that is delivered will tend to become approximately the same quantity over time. Chang et al., BPA, E-BPA-48, 8. Thus, there should be no overcollection of transmission costs from the proposed IS-87A rate.

PP&L/PGE disagrees with BPA's premise that allocations and use will tend to become equal over time. In particular, they contend that circumstances exist beyond the utilities' control which constrain the utilities from using allocated Intertie capacity. BPA agrees that if allocation and use do not become equal over time, there is a risk of overcollection. Diffely, BPA, TR 177.

The crux of this issue is whether the IS-87A billing determinant based on Intertie allocations will necessarily lead to a known, unreasonable over-collection of the revenue requirements. Both BPA and the parties acknowledge that there are conditions beyond the control of the Northwest scheduling utilities, including BPA, which could reduce the use of the Intertie. However, BPA and the parties disagree as to how the Intertie users in the Northwest would react to the IS-87A billing implementation. That is, a

Northwest scheduling utility may choose to hold allocated but unused Intertie capacity or reduce its declaration to more closely match its expected use. Chang, BPA, TR 189-190.

Under present circumstances where billing is based strictly upon actual use rather than allocation, BPA faces the risk of revenue undercollection. Nelson, PGP, E-PG-07, 2-3, 6. An Intertie charge based upon actual use alone indicates that BPA's ability to recover transmission costs rests largely with the scheduling utility. If a sale is not consummated, BPA recovers no revenue from the transmission capacity reserved for the scheduling utility. Id.

The assessment of a charge based upon allocation rather than use will provide an incentive for scheduling utilities to make a sale at a reasonable price whenever possible and will discourage utilities from holding unused allocations. Nelson, PGP, E-PG-07, 2-3, 6; Chang et al., BPA, E-BPA-28, 9. Once a utility receives its Intertie allocation, that utility has the exclusive right to use that Intertie capacity to either transmit energy or hold that transmission space. Chang et al., BPA, E-BPA-28, 9. This decision is exclusively within the utility's control and is a use of that transmission capacity for which BPA should be compensated. With the implementation of this billing application, utilities should be discouraged from holding unused Intertie allocations. Chang et al., BPA, E-BPA-48, 17.

BPA agrees with PP&L and PGE that there may be a risk of overcollection of revenue if allocation and actual use of transmission capacity do not equalize over time. However, there are sufficient reasons why this risk should not prevent BPA from adopting the proposed IS-87A rate.

First, BPA faces a risk of underrecovery in the absence of this charge. BPA, however, is obligated to establish rates that recover total costs and provide a reasonable degree of assurance that the Federal investment will be repaid. 32 FERC ¶61,014, 61,057, n. 14. The proposed IS-87A rate provides greater assurance that BPA will satisfy these statutory obligations. Second, no party has introduced testimony attempting to quantify the level of overcollection that may occur. The level could very well be insignificant, especially if BPA is correct that allocation and use will, in fact, tend to equalize over time. Third, to alleviate the extent of this problem, the IS-87A rate expressly provides that the amount of energy allocated but not scheduled that is subject to billing may be reduced pro rata by BPA due to forced Intertie outages and other uncontrollable forces that may reduce Intertie capacity. Fourth, language has been added to the rate schedule specifying that unused Intertie allocation that is received may be reduced by mutual agreement.

Decision

BPA believes that Intertie allocations and use should equalize over time, in which case there will be no overcollection of revenue from the IS-87A rate. The risk of overcollection that may exist is speculative, has not been quantified, and may well be insignificant. The IS-87A rate is necessary for

BPA to minimize the risk of revenue underrecovery and to satisfy BPA's obligation to recover costs and repay the Federal treasury.

Issue 2

Will the IS-87A rate produce an inequitable allocation of transmission costs between Federal and non-Federal uses?

Evaluation of Positions

BPA is required by statute to establish rates that equitably allocate the costs of the Federal transmission system between Federal and non-Federal users. 16 U.S.C. §839e(a)(2)(C); 16 U.S.C. §838h. It should be noted, however, that the equitable allocation standard does not require each specific transmission rate to result in an equitable allocation of costs among Federal and non-Federal users. Rather, the standard applies to BPA's rates overall. To satisfy this requirement, BPA has prepared separate rapayment studies for its power and transmission systems and segregated costs of the transmission system into nine transmission segments. In general, revenue responsibility for Federal and non-Federal users was developed for each segment using the 12 CP method of demand cost allocation.

Nevertheless, numerous utilities argue that the proposed IS-87A rate violates the equitable allocation standard because non-Federal users will be charged for allocated but unused Intertie capacity, while costs apportioned to Federal use will be based strictly upon actual use. Brattebo, PP&L, E-IO-05, 3; Prehearing Brief, MPC/PP&L, P-IO-01, 14 and 15; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 14; Exceptions, PSP&L et al., R-PS/MP/WP-01, 11-12; Initial Brief, PP&L/PGE, B-PL/GE-01, 61 and 62. In addition PP&L argues that equitable allocation must mean that the allocation of costs is proportional to some common billing determinant. Exceptions, PP&L, R-PL-01, 13. Although the equitable allocation requirement is not specific to each transmission rate, BPA believes that the IS-87A rate does, in fact, result in an equitable allocation of costs among Federal and non-Federal users.

Contrary to the arguments of PP&L and PGE, costs apportioned to Federal use under the IS-87A rate are not based upon actual use. As stated by BPA and acknowledged by PP&L and PGE, the entire basis for allocating costs on the Intertie for both Federal and non-Federal use is the projected use of the Intertie. Chang, BPA, TR 184; Brattebo, PP&L, E-IO-05, 4; Opening Brief, PP&L, B-PL/GE-01, 59. The focus of the parties' grievance is that the IS-87A rate is inequitable because it is designed to charge non-Federal utilities, but not BPA, for unused Intertie allocations. Although the IS-87A rate applies to non-Federal utilities only, it does not give rise to an inequitable allocation of costs or any other inequity.

Neither the word "equitable" nor the phrase "equitable allocation" are defined in BPA's statutes or legislative history. Clearly, the Administrator is vested with the discretion to determine what constitutes an equitable allocation of costs. Chevron, U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837, 843-844, 865 (1984). It is BPA's position that a

determination of whether costs are equitably allocated rests with the circumstances of each case. Although BPA agrees with PP&L that the use of common billing determinants is one way to equitably recover costs, it is not the only way. Similarly, Congress did not require that costs be "identically" allocated or allocated on a pro rata basis among Federal and non-Federal users. For the following reasons, BPA believes that costs of the transmission system have been allocated in an equitable manner between Federal and non-Federal users under the IS-87A rate.

First, BPA necessarily incurs all costs of the Intertie, regardless of whether sales are consummated or not. Thus, BPA must always incur a cost, potentially greater than that of scheduling utilities, for unused allocations. This fact was clearly explained during cross-examination of BPA's witnesses. For instance, BPA witnesses were asked:

> Q. Is there any other comparable rate or allocation that you know of that penalizes BPA for unused allocations?
>
> A. Bonneville has to recover the cost of the Intertie whether it is used or not.

Chang, BPA, TR 182.

Similarly, when this point was pursued further, BPA's witnesses were asked:

> Q. You have imposed a new -- you proposed a new basis for charging for Southern Intertie transmission to third party utilities under [IS-87A], that is, allocation versus deliveries. Have you done anything that would impose a similar rate or allocation penalty or any other charge for Bonneville if its allocations exceed its delivery?
>
> A. Bonneville has that built into its entire structure. We have incurred a notable level of cost to construct the Intertie. If it goes unused to a certain extent, yes, we pay the entire risk of that lack of usage.

Diffely, BPA, TR 183-84.

Thus, with the IS-87A rate, both BPA and non-Federal utilities incur a cost for unused Intertie allocations. BPA incurs a cost for unused allocations because BPA must repay the Federal investment in the Intertie, regardless of whether a sale is actually consummated. Non-Federal users incur this cost by paying for Intertie allocations as well as for actual deliveries. Conversely, in the absence of this charge, BPA would absorb all the risk and all the costs of unused Intertie allocations. The proposed IS-87A rate is a reasonable and equitable method of sharing the costs of the Federal transmission system between Federal and non-Federal users.

Second, BPA expects that the Intertie allocation received and actual energy delivered will tend to merge over time. Chang, BPA, TR 184; Chang et al., BPA, E-BPA-48, 8. This is because the IS-87A rate will discourage

utilities from holding unused Intertie allocations. Id. PP&L and PGE argue that allocations and use will not be identical due to minimum generation or other conditions in California that may prevent sales from occurring. Opening Brief, PP&L/PGE, B-PL/PG-01, 60. To address this concern the IS-87A rate has been modified to state that the amount of energy allocated but not scheduled that is subject to billing may be reduced upon mutual agreement by BPA and the customer. As a consequence, the reasons cited by PP&L and PGE for a disparity between allocations and use will be minimized and possibly eliminated.

Third, once a utility receives an allocation of Intertie capacity, it has an exclusive right to that capacity. Chang et al., BPA, E-BPA-28, 9. It is undisputed that BPA does not have the right to reallocate such Intertie capacity to any other utility in the event that the allocation received is unused. As noted by PGP, both BPA and other Intertie users lose potential power sales revenues when allocations are unused. Nelson, PGP, E-PG-07, 6. In addition, BPA looses potential transmission revenues. Id. The IS-87A rate mitigates BPA's potential loss of transmission revenue by insuring that a portion of BPA's transmission revenue requirements is recovered from non-Federal utilities, even if an Intertie allocation is unused.

Fourth, in the absence of this charge, non-Federal utilities receive a valuable right to Intertie capacity for free. A utility can use its allocation to transmit energy or simply hold its space for whatever reason it chooses. Chang et al., BPA, E-BPA-48, 8. BPA believes it is clearly equitable to charge non-Federal utilities for this valuable and exclusive right which directly impacts BPA's ability to recover power and transmission revenues.

Fifth, as the IS-87A rate discourages PNW utilities from holding unused Intertie allocations, it will increase the opportunities for BPA and other PNW utilities to gain additional Intertie access and use this capacity. Nelson, PGP, E-PG-07, 6; E-PG-05, 3. Accordingly, there is an opportunity for a greater volume of nonfirm energy sales to be made to the PSW, for total nonfirm energy revenues to the PNW to increase, and for competition among PNW utilities to increase. Chang et al., BPA, E-BPA-48, 7. This result will inure to the benefit of both the Pacific Northwest and Pacific Southwest.

Thus, BPA believes that all costs of the transmission system have been allocated in an equitable manner between Federal and non-Federal users under the IS-87A rate. Without IS-87A, (1) BPA absorbs all the risks and revenue losses associated with unused allocations, and (2) non-Federal utilities receive a valuable and exclusive right to Intertie capacity for free. The IS-87A rate will discourage utilities from simply holding these Intertie allocations and encourage wider use of the Intertie by a larger number of utilities. Competition as well as more efficient use of the Intertie will be facilitated. As Intertie allocations and use tend to merge over time, PP&L's concern about a common billing determinant will be rendered largely academic.

Decision

BPA incurs a cost for unused allocations that is equal to if not greater than the cost assessed under the IS-87A rate to non-Federal utilities. BPA

must recover the costs of the Intertie regardless of whether actual sales are consummated. It is equitable to allocate a portion of these costs to scheduling utilities who receive an exclusive right to Intertie capacity once they receive an allocation. The proposed IS-87A rate equitably allocates the costs of the Federal transmission system between Federal and non-Federal users.

Issue 3

Do factors beyond the control of a scheduling utility that may preclude an actual delivery detract from the need and reasons for assessing the IS-87A rate?

Evaluation of Positions

PP&L and PGE argue that there are situations beyond the control of Northwest utilities that will preclude actual deliveries to the Pacific Southwest. Initial Brief, PP&L/PGE, B-PL/PG-01, 62. PP&L cites minimum generation conditions in California as a principal example. Id. In general, PSP&L agrees with and supports PP&L's argument. Initial Brief, PSP&L, E-PS-04, 2; Laukhart, PSP&L, B-PS/MP/WP-01, 13.

PP&L and PGE further contend that under Conditions 2 and 3 of BPA's Near Term Intertie Access Policy, a Northwest utility cannot determine the amount of power it expects to sell until it has received an allocation and has offered the energy to the Southwest. Brattebo, PP&L, E-PL-02R, 1-5. According to PP&L, a utility's declaration is based on the amount of surplus energy it makes available for sale in the nonfirm market, not what it expects to sell. Id. PP&L also argues that at times the Intertie goes unused because the price established by BPA under Condition 1 is uneconomic for the Southwest. Id.

CPUC is opposed to the IS-87A rate because it is their contention that the misuse by PNW utilities of their Intertie allocations are problems of BPA's devise which should be remedied by reformation of the Intertie Access Policy. Exceptions, CPUC, R-CP-01, 9. However, no testimony has been submitted by CPUC nor is there evidence in the record to support this contention.

PGP supports the IS-87A rate. PGP's support appears to be based largely upon the grounds of economic efficiency and improved competition. PGP argues that basing the IS-87A rate on the larger of a utility's total use or allocation assures that utilities will not declare resources for an allocation in excess of expected sales to the Southwest. PGP argues further that utilities declaring resources that are uneconomical to operate solely to receive a greater allocation of the Southern Intertie adversely impact other users of the Intertie. PGP concludes that utilities should declare only the resources they intend to operate and use their total allocation to assure full use of the Southern Intertie capacity. Nelson et al., PGP, E-PG-05, 3. BPA, too, has testified that there is potential for efficiency and competition gains to be realized from the IS-87A rate. Chang et al., BPA, E-BPA-28, 9; Griffin, BPA, TR 228.

There may be some situations beyond the control of Northwest utilities that will preclude utilities from consummating transactions on the Intertie. A minimum generation condition in California is one example of such a situation. Similarly, there may be reasons why it is justifiable to assess a charge that varies with different Intertie access conditions, as suggested by PGP. However, the IS-87A charge is directed towards a different cost recovery goal.

As discussed in Issues 1 and 2, BPA is proposing to charge utilities for allocation rather than use because once an Intertie allocation is received, the scheduling utility has an exclusive right to use that capacity as it sees fit. As succinctly stated by BPA's witness, "the point is that the charge is going to be assessed on the physical capacity available on the Intertie." Griffin, BPA, TR 226. The utility's exclusive right to that physical capacity remains intact, regardless of the Intertie condition BPA is operating under or whether an actual sale is consummated.

Moreover, as discussed in Issue 2, BPA must recover Intertie costs regardless of whether Northwest utilities actually consummate sales or not. It is not uncommon for Northwest utilities to price energy above the decremental cost of California resources and thereby decrease the chances of an actual sale. Haines, BPA, TR 223. BPA should not be in a situation of directly losing transmission revenue that would otherwise be received due to the pricing practices of such utilities.

Nevertheless, the IS-87A schedule has been modified to address the parties' concerns. The IS-87A now provides that the amount of allocated but not scheduled energy that is subject to billing may be reduced upon mutual agreement by BPA and the customer. Therefore, BPA may accept return allocations when circumstances beyond the scheduling utility's control results in unused allocation.

The record is equivocal on the issue of whether there are economic efficiencies to be gained through the IS-87A rate. However, there is a potential for competitive and economic efficiencies to be achieved. The IS-87A rate would provide BPA a valuable opportunity to explore whether a scarce resource such as the Intertie could be more efficiently utilized through this rate structure. The IS-87A rate may serve to discourage utilities from holding allocated but unsold Intertie capacity, and thereby increase total Intertie use.

Decision

It is reasonable to assess a charge for the exclusive right to use the physical capability of the Intertie. Once a utility receives an allocation of Intertie capacity, it has an exclusive right to use that capacity. This is a use for which BPA should be compensated. Factors beyond the control of the scheduling utility that may preclude an actual delivery do not detract from the need and reasons for assessing this charge. Nevertheless BPA may accept return allocations in these or other circumstances. There also may be competition and efficiency gains to be realized from the IS-87A rate.

Issue 4

Will the IS-87A rate tend to reduce unreasonably the Pacific Northwest's total nonfirm revenues?

Evaluation of Positions

PP&L and PGE argue that under the IS-87A rate, once a Northwest utility receives an Intertie allocation, the utility has also incurred a transmission charge even if it makes no sale of energy. PP&L and PGE therefore conclude that Southwest utilities, knowing that Northwest utilities with allocations effectively are compelled to sell energy in order to recover the transmission charges, may be able to force energy prices down to levels that otherwise would be uneconomic for Northwest utilities. Brattebo, PP&L, E-IO-05, 2.

PP&L and PGE argue further that under truly competitive conditions, the IS-87A rate should not lead to unreasonably low prices. However, since a few California utilities monopolize the California portion of the Southern Intertie, PP&L and PGE conclude that there is a lack of competition for Northwest nonfirm energy among California utilities. Initial Brief, PP&L/PGE, B-PL/GE-01, 63; Oral Argument, PP&L, TR 3091-92.

PGP generally agrees with PP&L that BPA's proposal may have the effect of giving California utilities the ability to drive down the price of Northwest nonfirm energy and exploit a monopoly position on the Southern end of the Intertie. PGP also agrees that certain California utilities own shares of the Intertie which they need not share with other utilities. Nelson, PGP, TR 2466.

For two reasons, BPA takes issue with the conclusion that the proposed IS-87A rate will enable California utilities to force nonfirm energy prices down to uneconomic levels for Northwest utilities. First, to the extent the IS-87A rate discourages Northwest utilities from holding an unused Intertie allocation, there should be greater opportunity for other Northwest sellers to gain Intertie access and use this capacity. Accordingly, there is an opportunity for a greater volume of nonfirm energy sales to be made to the Pacific Southwest and for total nonfirm revenues to the Northwest to actually increase. Chang et al., BPA, E-BPA-48, 7. This result would be in the best interest of both the Northwest and Southwest.

Second, there has been no study or evidence introduced to demonstrate that prices will in fact be forced down to uneconomic levels. Chang et al., BPA, E-BPA-48, 7. Indeed, even PP&L's testimony equivocates by noting that this result is only a possibility. Brattebo, PP&L, E-IO-5, 2. Moreover, economy energy, by its very nature, is a product marketed on a purely voluntary basis. It will be sold only if it is in the economic interest of both the buyer and seller. Accordingly, the price of nonfirm energy will not be reduced to uneconomic levels.

Decision

The record does not support the allegation that the IS-87A rate will reduce total nonfirm energy revenues. It is more likely that precisely the

opposite result will ensue because of the potential for increased competition and utilization of the Intertie by a larger number of utilities. Therefore, the proposed IS-87A rate is retained in BPA's final rate proposal.

Issue 5

Should formal criteria or procedures be established for returning unused Intertie allocations?

Evaluation of Positions

PSP&L contends that BPA should allow for the transfer of unused allocations among utilities. Lauckhart, PSP&L, E-PS-04, 2-3. PGP agrees with PSP&L, stating that BPA should place a deadline on accepting return allocations, such as 11:00 a.m. of the day the allocation is made, to alleviate the situation where a utility will be compelled to sell in order to avoid incurring the Nonfirm Transmission charge without a sale. Nelson et al., PGP, E-PG-07, 4-5.

PP&L contends that a Northwest utility cannot determine the amount of nonfirm energy the Southwest utilities would be willing to purchase until after an allocation is received. Brattebo, PP&L, E-PL-02R, 2.

Under the proposed rate BPA, at its discretion, may agree to accept a utility's unsold allocation. If such an agreement is reached, the unsold allocation upon which the IS-87A rate is assessed will be reduced accordingly. Under the Exportable Agreement, BPA allocates to the requests of the Southwest parties and there is a reallocation process for changes in those requests. Griffin et al., BPA, E-BPA-30, 3. There may be conditions under which a utility would be unable to make a sale with a PSW utility and consequently might be left with an unsold allocation. BPA has the discretion to accept a utility's unsold allocation if such an agreement can be reached after prescheduling but before realtime operation. Griffin et al., BPA, E-BPA-61, 3.

Decision

Acceptance of unused allocations is an operating procedure, not a rate issue. Therefore, formal criteria for BPA's acceptance of a utility's unused Intertie allocation will not be included in the IS-87 rate schedule.

C. Southern Intertie Firm Power Transmission Rate (IS-87B)

Issue 1

Should the Firm Power Transmission rate be capacity based?

Evaluations of Positions

The Firm Power Transmission rate is proposed for firm Intertie wheeling for sales of PNW surplus firm power. This rate is applicable where a party

has executed a long-term firm Intertie agreement with BPA specifying its use. BPA proposed a capacity-based rate derived from the Intertie segmented costs and Intertie capability to conform to historical treatment of firm wheeling transactions and to reflect the take-or-pay concept associated with long-term rights of firm wheeling service. Chang et al., BPA, E-BPA-28, 10; Chang, BPA, TR 158.

BPA's initial proposal was developed partly in response to several recommendations received during BPA's Notice of Intent (NOI) to adjust its transmission rates. In response to the NOI, ICP recommended that BPA's initial proposal for transmission rates include a demand-type rate for firm wheeling on the Southern Intertie, similar to the FPT-85.1 rate, explicitly applicable to new contracts for assured Intertie access as well as to existing contracts. ICP believes that reference to assured Intertie access is important. ICP, WP-87-12, 1-2. Similarly, PSP&L advocated the concept of a firm (dollars per kilowatt-month) rate for assured use of the Intertie under firm power sales contracts. PSP&L, TR-87-5, 3. PSP&L argued that such a rate would be consistent with traditional ratemaking principles, as it would recover the cost of capital investment based on dedicated use. Id. PSP&L suggests that the rate should be offered on a basis similar to that applicable to transactions under the Washington Water Power Company's contract with Southern California Edison Company. Id.

In response to BPA's initial proposal, PGE states that BPA's calculation of the Firm Power Transmission rate fails to distinguish among the various types of firm sales having different capacity factors. PGE also contends that a capacity-based rate could result in an overcollection or undercollection of revenues depending on the load factor of the transactions. Therefore, charges should be based on actual energy usage, not on the simple commitment of a firm share of the Intertie. Kellerman, PGE, E-GE-01, 5-8.

In contrast, PGP states that basing the firm Intertie charge only on the energy component fails to provide a proper incentive for efficient use of available Intertie capacity. PGP also states that a firm transmission rate which fails to recognize transmission capacity utilization will result in underuse of Intertie capacity and underrecovery of transmission revenues. PGP recommends that BPA design its Firm Power Transmission rate for Conditions 1 and 2 assuming 100 percent utilization of capacity. Nelson et al., PGP, E-PG-07, 7. PGP later concluded that the assumption of 100 percent load factor is incorrect for the type of firm sales expected on the Intertie, and therefore firm Intertie charges should be based on energy when the load factor is less than 100 percent. Nelson et al., PGP, E-PG-09, 2.

In addition, PP&L argues that the Firm Power Transmission rate does not consider the characteristic of firm wheeling service which allows BPA or other utilities to transmit nonfirm energy when firm transmission services are not used. Brattebo, PP&L, E-PL-03SR, 2.

The method proposed by PGE, which is based on the load factor of a capacity contract, does not reflect the fact that the utility may choose at some time to transmit power up to its full contract capacity, which must be available to them. Chang et al., BPA, E-BPA-48, 9. BPA agrees with PGE to a

certain extent that a capacity-based rate fails to distinguish among the various types of firm sales having different capacity factors. BPA at this point, however, does not know what transactions will occur under this rate because it is proposed for the first time in this case. Therefore, load factors are unknown. Diffely/Chang, BPA, TR 168-170.

Arguments supporting a capacity-based rate associated with take-or-pay long-term firm wheeling agreements, as well as arguments supporting an energy-based rate associated with use of the Intertie at varying load factors, are well taken. A reasonable way to price a fixed-cost, capacity-constrained resource is according to contracted rights to this capacity. However, unused rights revert to the Northwest region for economy transactions and the PSW market tends to be seasonal such that the Intertie is sometimes unconstrained. Thus, firm transactions with higher load factors should pay more than firm transactions with lower load factors.

Decision

The Firm Power Transmission rate shall consist of both a capacity component and an energy component.

Issue 2

Should the Firm Power Transmission rate be the same as the Uniform Adder charge associated with BPA's firm power sales?

Evaluation of Positions

As described in Issue 1, BPA's initial proposal for the Firm Power Transmission rate was derived from segmented Intertie costs and Intertie capability. Chang, BPA, E-BPA-28, 10. In contrast, BPA's initial proposal for the Uniform Adder component of BPA's surplus firm power sales was developed from the Uniform Adder class of service based on energy projections. The resultant energy-based rate was then converted to a demand charge based on an assumed load factor of 54 percent. BPA, E-BPA-07, 40.

PP&L argues that it is discriminatory for BPA to charge Northwest utilities a rate for firm transmission services which is higher than the rate associated with BPA's own surplus power sales. PP&L states that BPA's effort in developing this rate to be consistent with other BPA firm wheeling rates does not justify the higher charge. Brattebo, PP&L, E-PL-03SR, 1 and 2.

PP&L further argues that it is likely that all Federal and non-Federal Southwest firm power sales will be made at similar load factors; therefore, to equitably allocate transmission costs between Federal and non-Federal uses, the costs applied to both types of users should be similarly calculated. Brattebo, PP&L, E-IO-05, 5. WUTC agrees that BPA should not implement the higher firm rate for access to the Southern Intertie. WUTC argues that costs allocated to Federal and non-Federal uses should be identical. Initial Brief, WUTC, B-WU-01, 11. PGE contends that the Firm Power Transmission rate is not consistently applied to firm sales made by BPA and non-Federal utilities. PGE

further contends that all uses of the Intertie should be charged consistently for the amount of Intertie used. Kellerman, PGE, E-GE-01, 5-8.

To achieve consistency between Federal and non-Federal use of the Intertie for firm transmission service, the two rates should be developed jointly. The Firm Power Transmission rate, IS-87B, should have both a capacity and an energy component and the SP Uniform Adder should have a capacity-only or an energy-only charge.

The demand and energy components of the Firm Power Transmission rate are based on uniform Intertie costs allocated to power and wheeling under the NF, SP, and IS-87A rates, which are combined into a Uniform Adder class. BPA, E-BPA-07, 39. Therefore, the overall rate is the same for Federal and non-Federal use. Costs allocated to the Adder class are divided equally between the demand and energy components. A net revenue requirement of $35.89 million (from $36.7 million of Intertie costs) is allocated to the Adder class. An energy charge of 0.69 mills per kilowatthour is computed as half of the revenue requirement divided by forecasted energy transactions on the Southern Intertie (26062 GWh); the demand charge of $4.32/kW/yr is half of the revenue requirement divided by 4156 MW (Intertie capability). This demand level is used as a proxy to a presumed annual noncoincidental billing demand associated with all of the transactions in the Uniform Adder class.

Calculation of the IS-87B and SP-87 Uniform Adder is shown in Tables 9 and 9a of the final TRDS, WP-87-FS-BPA-07. Costs and sales are annual averages or annual peaks for the rate period. The demand charge for wheeling service applies to contract demand, while the energy charge applies to actual use or expectations thereof. There is no all-energy or all-demand charge option in the IS-87B rate schedule. The Intertie transmission rate for SP sales and for firm Intertie wheeling will collect the same revenues at every load factor. This solution responds to the parties' concern for achieving consistency between Federal and non-Federal use of the Intertie for firm transmission service. IS-87B is adjustable with general transmission rate adjustments and is applicable for south-to-north as well as to north-to-south sales.

Decision

The Uniform Adder for SP sales will be the same as the IS-87B for firm wheeling on the Intertie.

D. Northern Intertie Rate (IN-87)

Issue

Should Federal use be included in the determination of the IN-87 rate?

Evaluation of Positions

The IN-87 rate is developed by dividing segmented costs by projected wheeling energy on the Northern Intertie segment. Chang et al., BPA, E-BPA-28, 11. PGE contends that BPA should include a projection of BPA's own use of the Northern Intertie in determining the total energy expected to be moved over this transmission segment. Kellerman, PGE, E-GE-01, 1.

B.C. Hydro (BCH) requests that BPA consider the use of an appropriate energy sales volume in the calculation of the IN rate that will provide revenue recovery in line with stated requirements. BCH argues that continued use of very low energy sales volumes has ensured BPA recovery of revenue significantly in excess of revenue requirements. BCH also is opposed to the Northern Intertie concept and the IN rate. BCH, TR-87-4, 1.

BCH raised concerns regarding formulation of the Northern Intertie as a participant in the 1983 and 1985 rate cases. As stated in the 1983 rate case, BPA's identification of Northern Intertie facilities as an intertie segment is based on a clear pattern of commercial use, as shown by the actual transactions between Canada and the BPA system. 1983 Rates ROD, WP-83-A-02, 357. Segmentation of the Northern Intertie was found to be appropriate in the 1985 rate case, consistent with the 1983 rate case, and is continued for this rate case.

Federal use of facilities connecting the Bonneville system and the B.C. Hydro system has been recognized through the segmentation process. Woerner, BPA, TR 195; Chang, BPA, TR 197-198. There are parallel lines between Custer and Monroe. One line is segmented to the Northern Intertie and the other is segmented to the Network. The line segmented as part of the Northern Intertie is predominately non-Federal use. There is a relatively small amount of Federal use on the Northern Intertie and, as in the 1983 rate case, this use does not contribute to peak hour loading. 1983 Rates ROD, WP-83-A-02, 357-359; Chang et al., BPA, E-BPA-48, 15.

Decision

The decision adopted by the Administrator in the 1983 ROD for determining use on the Northern Intertie is still appropriate. The IN-87 rate is properly based on expected non-Federal use and Federal use is accounted for through the segmentation process.

E. Market Transmission Rate (MT-87)

Issue 1

Does BPA have statutory authority to establish a value-based transmission rate?

Evaluation of Positions

Prior to this proceeding, BPA had only established cost-based transmission rates. For all conventional transmission services provided during this rate period, BPA is continuing to propose cost-based rates. However, in addition to these cost-based transmission rates, BPA has proposed one value-based rate called the Market Transmission rate, MT-87. The MT-87 rate is of extremely limited application because it applies to only transactions undertaken pursuant to the experimental Western Systems Power Pool (WSPP) Agreement.

The WSPP is a large-scale experimental power pool providing a wide range of bulk power services, including transmission services, to 10 states in the western United States at flexible market-based rates. The WSPP Agreement was enthusiastically approved by FERC on March 12, 1987 for a period of 2 years beginning May 1, 1987. Pacific Gas and Electric, 38 FERC ¶61,242 (hereafter referred to as WSPP Order). BPA is one of the initial 15 signatories to the WSPP Agreement. The 2-year period of the WSPP generally overlaps BPA's 1987 rate period.

There is no dispute that the MT-87 rate is the same transmission rate adopted by all other WSPP participants. Chang/Diffely, BPA, E-BPA-48, 2-3; Schultz, PSP&L, E-IO-04, 10. The MT-87 rate is a flexible rate that will vary between 1 and 33 mills per kWh, but will not exceed 33 percent of the difference between the highest and lowest decremental generation cost among WSPP participants.

PSP&L et al., CPUC, and SCE oppose the MT-87 rate because they allege that BPA is statutorily prohibited from establishing a transmission rate that is not cost-based. Exceptions, PSP&L et al., R-PS/MP/WP-01, 3-4; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 21, 14-18; Schultz, IOU, E-IO-04, 11; Reply Brief, CPUC, R-CP-01, 6-8, Initial Brief, CPUC, B-CP-01, 13; SCE, WP-87-7229, 31. These parties generally cite sections 9 and 10 of the Federal Columbia River Transmission System Act (Transmission Act) to support this argument. 16 U.S.C. §838g, 838h; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 15-17; Exceptions, CPUC, R-CP-01, 7; SCE, WP-87-7229, 31.

Section 9 of the Transmission Act states that overall, BPA's rates for the sale and transmission of electric power shall be established:

> (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles,
>
> (2) having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years . . .
>
> (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with

the issuance of and interest on all bonds issues and outstanding pursuant to the Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

Significantly, the parties do not identify the actual language in this lengthy provision that specifically forbids BPA from adopting a flexible value-based transmission rate. Rather, they simply conclude that this result ensues. Initial Brief, PSP&L, B-PS/MP/WP-01, 17; Exceptions, CPUC, R-CP-01, 7. BPA disagrees with their conclusion.

Section 9 of the Transmission Act does not contain any express directive regarding the establishment of cost-based rates. As such, the argument that section 9 precludes BPA from establishing a value-based rate rests solely upon implication. The parties do not cite any legislative history or other authority to support this implication. Although section 9 contains various references to cost recovery, it does not instruct the Administrator to design any particular rate in one fashion as opposed to another. On the contrary, the courts have interpreted section 9 of the Transmission Act to vest the Administrator with extremely broad ratemaking authority, and in particular with the authority to establish value-based rates.

In Pacific Power & Light Co. v. Duncan, 499 F. Supp. 672 (D.C. Or., 1980) (hereafter "PP&L"), PP&L challenged a BPA rate increase on procedural and substantive grounds. See also Montana Power Company v. Edwards, 531 F. Supp. 8 (D.C. Or., 1981). In particular, PP&L argued that BPA was statutorily precluded from adopting a share-the-savings rate because such a rate was value-based rather than cost-based. PP&L cited section 9 of the Transmission Act in support of its claim.

The court expressly rejected PP&L's argument and held that section 9 of the Transmission Act (1) does not preclude BPA from establishing value-based rates, and (2) vests the BPA Administrator with such a broad grant of ratemaking discretion that it precludes judicial review because there is no law to apply. Id. at 682. See also City of Santa Clara v. Andrus, 572 F. 2d 660 (9th Cir. 1978) cert. denied 439 U.S. 859 (1978). Although PP&L involved a challenge to BPA's power rates rather than transmission rates, the express language of section 9 of the Transmission Act refers to both. Accordingly, section 9 does not prohibit BPA from establishing value-based transmission rates.

The second statutory provision relied upon by the parties is section 10 of the Transmission Act, which, it should be noted, is incorporated into section 7(a)(2)(C) of the Northwest Power Act. 16 U.S.C. §839e(a)(2)(C). Section 10 of the Transmission Act provides that "the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system." 16 U.S.C. §838h. The parties generally argue that a value-based rate is incompatible with the requirement to equitably allocate costs.

This argument, however, suffers the same faults as the arguments regarding section 9 of the Transmission Act. The equitable allocation standard is not a rate design standard and neither expressly nor implicitly mandates cost-based

transmission rates. Nor does the standard mandate a pro rata allocation of costs among users. Rather, it directs BPA to allocate costs of the transmission system between Federal and non-Federal users in a manner determined by the Administrator to be equitable. A value-based transmission rate could certainly be designed to insure that the costs of the transmission system are equitably allocated. The relevant point is that the equitable allocation standard is not a blanket prohibition against all value-based rates. Had Congress intended to limit BPA to establishing cost-based transmission rates, it surely could have done so.

Moreover, the interpretation of the equitable allocation standard offered by the parties is inconsistent with PP&L. In PP&L, the court specifically cited the equitable allocation standard when deciding that BPA's statutory standards, taken as a whole, vest the Administrator with extremely broad ratemaking discretion, and in particular with the discretion to establish a value-based rate. 499 F. Supp. at 683.

Decision

Section 9 and 10 of the Transmission Act, and section 7(a)(2)(C) of the Northwest Power Act do not preclude BPA from establishing a value-based transmission rate.

Issue 2

Is the Market Transmission rate consistent with BPA's statutory obligations to (1) act as a carrier of non-Federal power and (2) make transmission service available on a fair and non-discriminatory basis?

Evaluation of Positions

Section 6 of the Federal Columbia River Transmission System Act requires BPA to make excess Intertie capacity available to non-Federal utilities on a fair and nondiscriminatory basis. 16 U.S.C. §838d. Section 6 of the Regional Preference Act provides that Intertie capacity in excess of BPA's needs shall be made available to non-Federal utilities as a carrier and that the transmission of such energy shall be at equitable rates. 16 U.S.C. §837e.

PSP&L et al., CPUC, and SCE argue that the MT-87 rate violates these standards. Exceptions, PSP&L et al., R-PS/MP/WP-01, 5-6; Initial Brief, CPUC, B-CP-01, 14; Reply Brief, CPUC, R-CP-01, 8; SCE, WP-87-7229, 31-32. In particular, PSP&L et al. contends that the Intertie was constructed to be a common carrier with the understanding that excess capacity would be made available at cost on a nondiscriminatory basis. Exceptions, PSP&L et al., R-PS/MP/WP-01, 6-7. Although BPA agrees that Intertie capacity in excess of BPA's need is to be made available to other utilities on a nondiscriminatory basis, BPA does not agree that the Intertie is a "common" carrier or that every transmission rate established by BPA must be cost-based.

First, as discussed in Issue 1, there is no express language contained in the statutory provisions identified by the parties that directs BPA to

establish only cost-based rates. In the absence of an express prohibition, the parties' argument exists solely by implication. However, the authority cited to support this implication is not persuasive.

For instance, PSP&L et al. refers to a 1964 report to the Congressional Approriations Committee. Exceptions, PSP&L et al., R-PS/MP/WP-01, 5-6. This document, however, is inapposite because the portion quoted by PSP&L does not make any reference to establishing cost-based rates. PSP&L et al. references two other documents as well: an alleged press release and a letter allegedly signed by former BPA Administrator Luce. Id. These documents are problematic because they have been referenced without citation and are not part of the record established in this proceeding. As such, they may or may not be taken out of context, cannot be reviewed by BPA, and have not been available for scrutiny by other parties. Moreover, since these documents do not represent the voice of Congress, they do not constitute persuasive legislative history. Even if all these serious obstacles could be overcome, the vague reference to cost recovery contained in the 1962 letter certainly does not preclude the Administrator from establishing a value-based transmission rate.

Second, although the Intertie is available as a carrier, it is not a "common" carrier. Indeed, in Department of Water & Power of the City of Los Angeles v. BPA, 759 F. 2d 684 (9th Cir. 1985), the court recognized that BPA is statutorily mandated to establish an Intertie access policy that is intended to mitigate projected financial deficits, even though that policy restricts and in certain instances precludes access of non-Federal entities.

Third, Congress has recognized that even common carriers may establish market-based rates without derogating their common carrier obligations. 49 U.S.C. §10701a(a) (Staggers Act authorizing railroads to establish "any rate" for transportation or other services); 49 U.S.C. §1551(a)(2)(B) (abolishing the requirement that airline rates be just and reasonable).

Fourth, the record in this proceeding is devoid of any evidence that under the MT-87 rate the status of the Intertie as a carrier of excess capacity will somehow be compromised.

Based upon testimony of PSP&L's witness, it appears that PSP&L's grievance lies more with the overall concept of a value-based transmission rate rather than with its legality. Schultz, IOU, E-IO-04, 8-9. It should be emphasized however that, with the exception of the MT-87 rate, every wheeling rate in this proceeding is cost based. Conventional wheeling service provided by BPA will continue to be provided through BPA's other transmission rates. The MT-87 rate is of extremely limited application and the wheeling services provided under the experimental WSPP Agreement rate will supplement rather than replace BPA's standard cost-based wheeling rates. The additional transmission revenue received under the MT-87 rate will inure to the benefit of all BPA customers and enhance BPA's ability to recover costs and repay the Federal treasury.

Decision

The MT-87 rate is consistent with BPA's statutory obligations to (1) act as a carrier of non-Federal energy and (2) make transmission capacity available on a fair and nondiscriminatory basis.

Issue 3

Will the MT-87 rate result in inequitable allocation of FCRTS costs between Federal and non-Federal users?

Evaluation of Positions

The CEC asserts that because BPA forecasts no revenues from the MT-87 rate, revenues actually received (in excess of revenue under otherwise applicable rates) would lead to overrecovery of BPA's revenue requirement. Chamberlain, CEC, E-CC-01, 62. PSP&L et al. and SCE argue that the equitable allocation standard is violated by a value-based rate such as MT-87 because different standards would apply for Federal and non-Federal use. That is, a value-based pricing system would be applied for non-Federal customers while Federal power would be transmitted on a cost basis. Exceptions, PSP&L et al., R-PS/MP/WP-01, 8; SCE, WP-87-7229, 31. These positions are not well taken.

First, as discussed in this Chapter, Section B, Issue 2, the equitable allocation requirement is not specific to each particular transmission rate schedule. Rather, it applies to BPA's rates overall and has been fully satisfied.

Second, the argument that different standards apply for Federal and non-Federal use was not developed and is difficult to understand. As discussed in Issue 1, the MT-87 rate applies only to an extremely limited group of transactions, those undertaken pursuant to the WSPP Agreement. All other BPA wheeling services in this proposal are provided on a cost basis. There is no dispute that BPA's Intertie Adder, which is the transmission rate component of BPA's own power sales to the PSW, is also cost based. SCE, WP-87-7229, 31. Thus, BPA's transmission rates for all conventional wheeling services provided to Federal and non-Federal users in this proposal are cost based. Similarly, there is no difference in treatment between Federal and non-Federal users under the MT-87 rate. With the MT-87 rate, all signatories to the WSPP Agreement will be assessed a charge for wheeling service under an identical rate structure.

Third, as explained in BPA's testimony, BPA has not allocated any transmission costs to MT-87 or included revenues from the MT-87 rate in this rate proposal. Chang et al., BPA, E-BPA-48, 15. This is because transactions under the WSPP Agreement are experimental, revenues are speculative, and projections could easily overstate total BPA revenues. Id. These uncertainties could result in BPA improperly reflecting the magnitude of credits in BPA's generation and transmission revenue requirement. Id., 14-15. Additionally, revenues collected from the MT-87 rate may displace revenues that would have been collected through other rate classes. Id.

BPA anticipates that revenue recovered under MT-87 will be equitably credited to generation and transmission in a manner similar to the treatment of ET and NF revenues. Chang et al., BPA, E-BPA-48, 14. However, the explicit treatment of such revenues will be described in subsequent rate proposals as information is compiled on the level and types of transactions involved. Id. This treatment is consistent with the treatment allowed by FERC for other WSPP participants. WSPP Order, 38 FERC ¶61,242, 61,799.

Decision

The MT-87 rate will not result in an inequitable allocation of FCRTS costs between Federal and non-Federal users.

Issue 4

Is the MT-87 rate unreasonably indefinite and anticompetitive?

Evaluation of Positions

The objective of the WSPP Agreement is to increase competition and explore a reasonable means to increase opportunities for mutually and societally beneficial power transactions. Chang et al., BPA, E-BPA-48, 7; WSPP Order, Slip op., 3, 14, 24. The MT-87 rate is designed to meet this objective.

WSPP participants believe that the coordination market is sufficiently open for them to benefit from the flexible pricing scheme established under the Agreement. Id. The participants are committed to the goal of increasing rather than limiting economic coordination. Id.; Chang et al., BPA, E-BPA-48, 4-5. The MT-87 rate will allow BPA to participate in the WSPP experiment on an equal basis with other WSPP members. Chang et al., BPA, E-BPA-28, 12.

CEC argues that BPA has not indicated how far in advance of a transaction the MT-87 rate will be set, what criteria and procedures will be used to set the rate, or whether the rate would result in a higher or lower charge than the otherwise applicable ET-87 or IS-87A rates. Chamberlain, CEC, E-CC-03, 13; Exceptions, CEC, R-CC-01, 25. CEC also argues that because Intertie capacity is a scarce resource BPA can use its virtual monopoly control to restrict competition. Chamberlain, CEC, E-CC-03, 15. CPUC argues that while flexibility in pricing may be necessary for utilities not statutorily bound to wheel electrical power, the obligation of BPA to act as a carrier fairly and without discrimination obviates that need. Exceptions, CPUC, R-CP-01, 9.

The MT-87 rate is identical to the transmission service and compensation schedule allowed under Schedule D of the WSPP Agreement. As a WSPP participant, BPA will adhere to the terms and conditions of the Agreement in providing service under the MT-87 rate. The Agreement provides that pricing and availability of transmission service are subject to the discretion of a transmission owner. However, because pricing information will be determined in advance of a transaction, a potential transmission customer will be provided with adequate information. Chang et al., BPA, E-BPA-48, 2.

On March 12, 1987, FERC approved the WSPP Agreement and found that: (1) the generation and transmission rates contained therein are just and reasonable, WSPP Order, 38 FERC ¶61,242; (2) definitive boundaries for price fluctuations will promote certainty by providing reference points for the WSPP participants, Id., 61,797; and (3) claims that the proposed rates are anticompetitive and would promote monopolistic practices were unfounded, Id., 61,789-798. On the contrary, FERC expressly held that the WSPP Agreement has the potential for enhancing competition in coordination markets. Id.

Decision

The MT-87 rate adopts the identical transmission pricing structure established in the WSPP Agreement. The WSPP pricing structure was found by FERC to be just and reasonable, and sufficiently definite to further the goals of the WSPP Agreement. By adopting the MT-87 rate, BPA will be on an equal competitive basis with other WSPP transmission owners. Furthermore, FERC rejected all claims that the WSPP Agreement and the rates contained therein would inhibit competition.

Issue 5

Has BPA raised issues concerning BPA's proposed transmission rates for the first time in the Draft ROD in violation of section 7(i) of the Northwest Power Act?

Evaluation of Positions

PSP&L et al. states that in the Draft ROD BPA argued for the first time that BPA's rates for transmission on the Southern Intertie need not be based on the costs of service. Exceptions, PSP&L et al., R-PS/MP/WP-01, 2-3. As a consequence, PSP&L concludes that BPA violated section 7(i) of the Northwest Power Act by not providing cross-examination on this issue. Id., 2. This argument is completely unfounded.

The fact that BPA proposed a value-based transmission rate was fully explored throughout this proceeding. All facets of the proposed MT-87 rate were examined in BPA's initial Transmission Rate Design Study, direct testimony, and rebuttal testimony. BPA, E-BPA-07, 9-10; Chang/Diffely, BPA, E-BPA-28, 12; Chang/Diffely, BPA, E-BPA-48, 1-7. Based upon BPA's testimony, PSP&L filed testimony opposing the MT-87 rate, as well as the Lost Opportunity rate, and argued against adoption of both rates primarily because they were not cost-based. Schultz, IOU, E-IO-04. PSP&L's Initial Brief urged rejection of these rates for precisely the same reason and contained extensive reference to and discussion of BPA's statutory ratemaking directives which PSP&L et al. allege preclude establishment of value-based rates. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 12-21.

In response, BPA's Draft Record of Decision clearly set forth BPA's argument in support of the legal authority to establish a value-based transmission rate. Draft ROD, WP-87-A-01, 203-207. If the PSP&L et al. grievance is that BPA's legal argument was not set forth at an earlier stage

of this proceeding by BPA witnesses, that position is not well taken. It is beyond the scope of technical witness expertise to testify on matters of law or reach legal conclusions.

Decision

BPA did not raise any issues regarding transmission rates for the first time in the Draft Record of Decision and did not violate the requirements of section 7(i) of the Northwest Power Act.

Issue 6

Is it appropriate for BPA to adopt the MT-87 rate?

Evaluation of Positions

The MT-87 rate reflects BPA's adoption of the transmission service pricing method developed through the WSPP Agreement. The rate is available only for transmission services provided to WSPP participants pursuant to the WSPP Agreement. Chang et al., BPA, E-BPA-28, 12.

CEC asserts that while BPA is working entirely through its established rate structure for power sales under the WSPP Agreement, a new value-based rate is being created for WSPP transmission. Chamberlain, CEC, E-CC-01, 59. IOU states that BPA should use its other cost-based rates for nonfirm transmission under WSPP. Schultz, IOU, E-IO-04, 11. SCE states that the MT-87 rate is not appropriate where BPA has established tight control of the market over the Southern Intertie. SCE, WP-87-7229, 31.

BPA has sufficient power sales pricing flexibility through the NF and SP rates to market energy under the WSPP experiment. In contrast, BPA lacks pricing flexibility in existing transmission rates. Chang et al., BPA, E-BPA-48, 4. The MT-87 rate is identical to the rate adopted by the WSPP participants and is designed to be consistent with the pricing flexibility concept for transmission services provided under the WSPP experiment.

In its WSPP Order, FERC enthusiastically approved of the WSPP Agreement and the transmission rates contained therein. The chief purpose of the WSPP experiment is to identify whether transmission transactions will increase with increased pricing flexibility. WSPP Order, 38 FERC ¶61,242, 61,782, 61,786-787. The WSPP participants agree that fixed cost-based transmission rates will not provide adequate incentives for participants to make available transmission capacity which they are using to serve their customers. Id., 61,797. If BPA were limited to fixed cost-based transmission rates, while other participants enjoyed flexible market-based rates, BPA's participation in the WSPP experiment would be of limited value. Furthermore, the transmission services contemplated under WSPP could range from nonfirm to various degrees of firm, such that BPA's fixed transmission rates could not always be compensable with the services provided. Chang et al., BPA, E-BPA-48, 6.

Decision

It is appropriate for BPA to adopt the MT-87 rate which is identical to the rates approved by FERC for transmission service under the WSPP Agreement.

F. Lost Opportunity Rate (IS-87B2)

Issue

Should BPA adopt the Lost Opportunity rate?

Evaluation of Positions

In the initial proposal, BPA identified three rate components of the Southern Intertie rate schedule. One of the components, the Lost Opportunity rate (LOR), was proposed for firm wheeling of firm transactions other than firm power sales of Pacific Northwest scheduling utilities, including capacity/energy and seasonal exchanges, capacity sales, and transactions involving extraregional resources. Chang et al., BPA, E-BPA-28, 10-11.

The LOR was intended to operate in conjunction with BPA's proposed Long Term Intertie Access Policy (IAP), which would permit assured delivery for certain Pacific Northwest surplus firm power sales. However, the proposed Long Term IAP would generally not permit assured delivery for certain other transactions, such as capacity/energy and seasonal exchanges, capacity sales, and transactions involving extraregional resources. The Lost Opportunity rate was intended to be applied only to these latter transactions, which the proposed Long Term IAP would restrict. In practice, BPA would relinquish its own Intertie allocation under the IAP to permit a non-Federal utility to gain access for the kind of transactions contemplated under the LOR. At the same time, the Lost Opportunity rate was intended to hold BPA revenue harmless for relinquishing Intertie capacity to non-Federal utilities.

The LOR would have enabled BPA to recover the costs incurred by BPA for relinquishing its own Intertie allocation. These costs would include: (1) loss to BPA of the economy energy market; (2) loss to BPA of firm capacity sales benefits; (3) operational cost to BPA associated with potential changed operations; and (4) costs to BPA of forgone revenues that result from the imports to the PNW of displacing loads that would otherwise be served by BPA. Thus, the opportunity costs incurred by BPA would be the basis for the particular charge assessed. Chang, BPA, TR 153; Chang et al., BPA, E-BPA-48, 10-11, 25. The actual charge, bracketed by a floor and a ceiling, would be transaction specific to help ensure that BPA was held financially harmless for providing assured Intertie access.

The parties strongly object to the Lost Opportunity rate for a variety of reasons. A number of parties oppose the LOR because it was not based upon the embedded cost of transmission service. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 17; Exceptions, PSP&L et al., R-PS/MP/WP-01, 3-10; Initial Brief, PGP, B-PG-01, 36-37; Initial Brief, CEC, B-CC-01, 34-35; Initial Brief, CPUC, B-CP-01, 13; Exceptions, CPUC, R-CP-01, 6-8; SCE, WP-87-7229, 31.

In addition, CPUC, CEC, and PSP&L et al. generally argue that the proposed Lost Opportunity rate is anticompetitive and demonstrates BPA's intent to exercise monopoly control over the Intertie. Initial Brief, CPUC, B-CP-01, 14; Exceptions, CPUC, R-CP-01, 9; Initial Brief, CEC, E-CC-01, 36; E-CC-03, 16-18; Exceptions, CEC, R-CC-01, 25; Schultz, IOU, E-IO-04, 9. 2/ The IOU argue that the kinds of transactions subject to the proposed LOR should be wheeled under the cost-based Firm Power Transmission rate. Schultz, IOU, E-IO-04, 10.

Allegations were also raised that the Lost Opportunity rate does not comply with FERC's separate accounting requirements or the equitable allocation standard. Nelson, PGP, E-PG-05, 4; Initial Brief, PSP&L et al., B-PS/MP/WP-01, 17. In summarizing the level of opposition to the LOR, PGP notes that not a single potential seller or buyer under the rate supports it. Exceptions, PGP, R-PG-01, 13-14.

BPA proposed the Lost Opportunity rate with the belief that the benefits to a buyer and seller from a transaction contemplated under the LOR would exceed the opportunity costs incurred by BPA for relinquishing its Intertie capacity. As a consequence, a transaction between PNW sellers and California buyers could be consummated which, without this rate, would most likely be precluded. The Lost Opportunity rate would thereby create a win/win situation where BPA, PNW utilities, and PSW utilities all benefit from a transaction under the LOR.

In the Draft ROD, BPA fully addressed each of the parties' arguments against the LOR and expressed general disagreement with these arguments. Draft ROD, WP-87-A-01, 203-212. BPA still abides by those arguments. However, the parties have reiterated their dissatisfaction with the LOR and clearly indicate that there would not be a buyer or seller willing to transact under this rate.

2/ PG&E originally supported the development of rates for these services. In response to BPA's Notice of Intent to adjust transmission rates, PG&E suggested that "the rates which are developed should be market based in order to reflect and utilize the realities of competition as a means of resolving [intertie] allocation problems, instead of relying on administrative allocation mechanisms." PG&E, TR-87-3, 1. PG&E, along with SCE, later opposed the rate for the same reasons as the IOUs. PG&E, WP-87-7494, 9; SCE, WP-87-7229, 32-33.

Decision

The Lost Opportunity rate is withdrawn from this rate proposal because of the parties' opposition. If and when a potential buyer and seller indicate a willingness to consummate a transaction of the type contemplated under the Lost Opportunity rate, BPA may explore ways to enable the transaction to be consummated while eliminating the potential adverse impacts of that transaction on BPA's revenues. This may be accomplished in a number of ways,

one of which would be for BPA to establish a special rate through a separate 7(i) public process for that specific transaction or a defined group of transactions.

G. Other Transmission Rate Issues

Issue 1

Does the inclusion of certain plant investment costs of the 3rd AC Intertie project in the 1987 rate proposal preclude participation in the project by others?

Evaluation of Positions

PSP&L et al. states that including costs for plant investment in the 3rd AC Intertie Project in the 1987 rate proposal fails to reflect BPA's commitment to allow others to participate in the project and thereby reduce BPA's investment. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 20; Lauckhart, PSP&L, E-PS-04, 1. PSP&L et al. argues that BPA has made a commitment to participation in the 3rd AC Intertie Project by non-Federal users and BPA's assumptions in this rate case should reflect that commitment. Exceptions, PSP&L et al., R-PS/MP/WP-01, 13.

There are certain existing capacitors (Fort Rock) that are currently part of BPA's existing transmission grid (Grizzly-Malin #1) which are scheduled to be replaced in FY 1989. Chang/Dohleman, BPA, TR 192. The replacement project calls for upgraded capacitors in anticipation of the 3rd AC Intertie Project. The scheduled purchase and installation of these capacitors in FY 1989 reflects, in part, the limited vendor manufacturing capability for capacitors. Therefore, inclusion of these costs in the rate proposal is properly identified in the Revenue Requirement Study. Roberts, BPA, E-BPA-47, 25. The fact that the identified costs associated with this project may be incurred wholly by BPA does not necessarily preclude (or include) others from participating in the 3rd AC Intertie Project. BPA has not made any commitment in this proceeding with regard to the participation by others in the 3rd AC Intertie Project. Participation in the 3rd AC Intertie Project will be decided outside of this rate case. Chang et al., BPA, E-BPA-48, 13.

Decision

Plant investment costs of the 3rd AC Intertie project are appropriately included in the 1987 rate proposal. Participation in the 3rd AC Intertie Project will be decided outside of this rate proceeding.

Issue 2

Should the determination of Metered Demand as described in the General Transmission Rate Schedule Provisions (GTRSP) be eliminated?

Evaluation of Positions

PSP&L et al. states that the requirements for determination of Metered Demand in the GTRSP are overreaching, are not evenhanded, and should be eliminated. Initial Brief, PSP&L et al., B-PS/MP/WP-01, 20; Lauckhart, PSP&L, E-PS-04, 3.

The Metered Demand description has been in place since 1965. The Metered Demand billing factor is evenly applied to all BPA's metered customers. In addition, a mechanism is in place for resolving disputed billing amounts. Chang et al., BPA, E-BPA-48, 17.

Decision

The determination of Metered Demand as described in the GTRSP is reasonable and should be maintained.

CHAPTER XI

ENVIRONMENTAL ASSESSMENT

BPA identified and evaluated potential environmental impacts of its 1987 rate proposal in an Environmental Assessment (EA), as described under Council on Environmental Quality (CEQ) regulations that implement the National Environmental Policy Act of 1969 (NEPA). The Draft EA was entered into the Official Record of the rate proceeding as WP-87-E-BPA-08. The EA was sponsored by BPA witnesses Robert E. Diffely and Sheryl E. Palmatier in testimony WP-87-E-BPA-31. The EA was submitted to the Department of Energy (DOE) for review and approval. After DOE approval, the EA was offered for public comment and review. The public comment period ended April 10, 1987. No questions on the EA were received during cross-examination of the BPA witnesses.

The analysis and discussion in the EA were based on assumptions and conditions existing previous to BPA's initial rate proposal. Therefore, the alternatives analyzed in the EA (the No Action alternative, the Proposed alternative, and the High Increase alternative) were designed to encompass the range of potential impacts that could result from any reasonably expected rate proposal. The assumptions and forecasts made for BPA's initial, supplemental, and final rate proposals are within the range of potential impacts analyzed in the EA.

In fact, as presented in BPA's final proposal, the percentage increase in revenue requirement for the effective period of the proposed rates (FYs 1988 and 1989) over the revenue requirement for the current rate period (FYs 1986 and 1987) is less than the percentage rate of inflation for the same period. At the time the environmental analysis for the rate case was prepared, the amount of rate increase was unknown. The EA thus evaluates a range of proposals and potential impacts.

BPA prepared a Finding of No Significant Impact (FONSI) based on the EA and comments of reviewers. The FONSI was approved by DOE prior to BPA's issuing of the final Record of Decision for the rate proceeding. WP-87-FS-BPA-09.

The following issues were raised by several participants and parties who submitted letters during the public comment period.

Issue 1

Should BPA exempt certain subclasses of ratepayers from the proposed rate increase?

Evaluation of Positions

One commenter states that retirement communities should be exempted from the proposed BPA wholesale power rate increase examined by the EA, because

BPA's proposed rate increase could adversely affect low- and fixed-income persons. Panorama Corporation, WP-87-7007E. Although socioeconomic impacts are not specifically analyzed in the EA, their potential is acknowledged throughout the EA. See, for example, BPA, E-BPA-08, 26, 35. (The references to potential socioeconomic impacts in Chapter 3 of the EA are based on the information contained in past BPA Environmental Impact Statements. For example, see BPA's 1983 Wholesale Power Rate Final Environmental Impact Statement, section III.B.2.) See Issue 7 regarding the EA's treatment of potential socioeconomic impacts.

Because the Administrator recognizes that BPA's wholesale power rates can affect ratepayers, the agency actively sought comments from the public in reviewing BPA's planned program spending levels for the current and next two fiscal years. Comments were received in a process prior to and separate from the current rate proceeding. As a result of these efforts, BPA's planned spending levels were reduced several times over the last several months, even after BPA's initial rate proposal. BPA submitted supplemental testimony during the rate proceeding that reflected these changes in revenue requirements.

BPA's wholesale power rates include a provision designed to provide residential customers with low-cost Federal hydropower--the residential and small farm power exchange described in section 5(c) of the Northwest Power Act. In the exchange, utilities sell BPA the amount of power needed to serve their residential and small farm consumers. BPA in turn sells the utilities an equal amount of power at the Priority Firm Power rate, which is based on the cost of BPA's lowest-cost resources. The benefit of this cost saving is passed on to the residential and small farm ratepayers by their utilities.

BPA sells wholesale electric power to utilities, rather than to end-use consumers. Many retail electrical utilities and charitable organizations attempt to mitigate the potential impacts of electricity prices with special programs for ratepayers. These programs include budget payment plans and discounted retail rates for senior and low-income ratepayers. Such retail rate programs are more appropriate and more effective than an action taken at the regional wholesale power rate level, since they can be targeted to the consumers who need them the most.

Decision

BPA recognizes the potential impact on ratepayers of its wholesale power rate increases, and has made efforts to mitigate such potential impacts by reducing the amount of proposed rate increase. Specific subclasses of ratepayers who potentially could be adversely affected by electricity rates are more appropriately helped at the retail level than through regional wholesale power rates.

Issue 2

Why does the scope of the EA not include evaluation of the impact of specific rate designs on the environment?

Evaluation of Positions

One commenter argues that the scope of the EA is too restrictive in that it does not include specific rate design issues which may impact the environment, citing the IS-87 Lost Opportunity Rate as an example. City of Tacoma, WP-87-7366E.

As stated in the EA, the environmental analysis of the 1987 rate proposals is focused on BPA's rates as a package for overall revenue recovery rather than on a study of specific rate designs. BPA, E-BPA-08, 3. This is because BPA is required by law to set its rates with the goal of recovering its revenue requirement as a whole; the Federal Energy Regulatory Commission reviews BPA's rates with this one criterion in mind.

The commenter states that the "EA should investigate environmental impacts of specific rates such as IS-87 which prematurely encourage the construction of replacements to the Pacific Southwest Intertie." City of Tacoma, WP-87-7366E. The EA addresses the potential impact of BPA's rates on transmission facility construction and concludes that construction of transmission facilities solely to respond to BPA's rate levels is unlikely for several reasons. BPA, E-BPA-08, 47. First, overall, BPA's transmission rates have stabilized. Second, construction of transmission facilities is a major decision requiring consideration of many factors in addition to the price of BPA's service. Id.

Finally, the proposed Lost Opportunity rate has been withdrawn from BPA's fianl rate proposal. See WP-87-FS-BPA-07 and Chapter X.

Decision

BPA's Environmental Assessment properly examines the potential environmental effects of BPA's overall revenue recovery rather than specific rate design. BPA's rates are designed as a package to recover BPA's revenue requirement over the rate period.

Issue 3

What alternative scenarios should the EA examine?

Evaluation of Positions

The EA examines a No Action alternative, assuming no change in the level of current rates; a Proposed alternative, assuming a uniform 10 percent increase in BPA's wholesale power rates; and a High Increase alternative, assuming a uniform 35 percent increase. BPA, E-BPA-08, 8-10.

One commenter contends that the proposed 10 percent rate increase scenario is unrealistic because rates remain at the same level throughout the forecast period rather than increasing with time. City of Tacoma, WP-87-7366E.

The EA's use of a 10 percent rate increase beginning in the next rate period and held stable in nominal terms over the entire period of analysis (through FY 2000) is a simplifying assumption intended to isolate the effect of a 10 percent increase in the current period. BPA, E-BPA-08, 9. This assumption provides a reasonable way of isolating the potential environmental impacts of a 10 percent rate increase beginning now and continuing for the period of analysis. This type of analysis has been used in environmental documents analyzing BPA's rate proposals since the 1982 Environmental Impact Statement.

Another commenter states that the alternatives analyzed by the EA are unreasonable, claiming that the EA's No Action alternative is fiscally and politically impossible and the High Increase alternative is politically unlikely and does not represent a plausible BPA action. Northwest Conservation Act Coalition, WP-87-7206E. It may be true, as NCAC claims, that BPA realistically is unable to reduce the level of its revenue requirement such that no rate increase would be necessary for FY 1988 and 1989. See ROD Chapter XII, Issue 1. However, BPA presented a "no action" alternative and a "worst case" alternative to bound the range of potential impacts of the rate proposal as analyzed in the EA. The "no action" alternative is not a "straw man," as NCAC claims, since BPA could indeed make the fiscal determination that it could avoid a rate increase for the next rate period. Several parties and many participants in the rate proceeding proposed that BPA avoid any rate increase. As discussed in Chapter XII, Issue 4, however, a zero rate increase in the next rate period could lead to much higher BPA rates in future rate periods. The No Action alternative provides a reasonable "base case" for analysis.

BPA presented a "worst case" alternative as an upper bound on the range of potential impacts. The EA's High Increase (the "worst case") alternative was set at 35 percent early in the rate development process. A 35 percent increase approximated the highest potential rate increase, assuming no cost-cutting effort by BPA, extreme revenue shortfalls (resulting from low oil and gas and aluminum prices, for example), and major changes in Treasury repayment methodology, as posited publicly by then-Administrator Peter Johnson in the summer of 1986. BPA's No Action and High Increase alternatives effectively and realistically set the bounds for the potential environmental impacts of BPA's rate proposal.

NCAC suggests two alternatives for the EA to analyze in comparison to the proposed action. First, NCAC suggests that the EA should compare "[BPA's] initial rate filing to its recently revised rate filing." NCAC, WP-87-7206E. The rate increase proposed in BPA's initial rate filing (11.5 percent for BPA's preference customers) and the rate increase proposed in BPA's supplemental proposal (8.5 percent for the preference customers), however, simply do not encompass a large enough range of potential impacts on a regional basis to allow for meaningful environmental analysis. The difference in regional loads between the High Increase and No Action cases analyzed in the EA (the difference being the maximum potential impact) is only 4-5 percent. BPA, E-BPA-08, 40. This difference is considered to be insignificant; NCAC's proposed alternatives logically would result in an even smaller difference. Second, NCAC suggests that "the EA should evaluate the

effects of a rate alternative designed to fully fund . . . the High Conservation scenario evaluated in BPA's Resource Strategy." NCAC, WP-87-7206E. While evaluation of program spending levels is outside the scope of the rate proceeding, a revenue level set to recover the high conservation scenario likely would fall within the range of revenues analyzed in the EA. See ROD Chapter I and Chapter XII, Introduction, regarding program spending levels.

Decision

The alternatives analyzed in the EA provide a practical range of rate increases for analysis of the potential impacts of the proposed rate increase and the issues addressed in the rate proceeding. The alternatives are reasonable and provide a bound on the range of potential environmental impacts resulting from BPA's rate proposal.

Issue 4

How should the EA's tabular data on end-user electrical energy consumption be shown?

Evaluation of Positions

EA Table 3 shows the "Percent Change in Energy Sold to Each Public Retail Sector, 1981 to 1985." The table shows the annual percentage changes in kilowatthours sold to major end-use consuming sectors of public utilities. BPA, E-BPA-08, 19. EA Table 8 shows "Projected Public Residential Energy Loads Under Revenue Level Alternatives, FY 1990 and FY 2000." Id., 27.

One commenter argues that EA Table 3 should be modified to reflect energy consumption on a per-customer basis to better show "end-user responses." City of Tacoma, WP-87-7366E. Table 3 is presented for general information only, since end-use consumption of electricity is affected by many factors. BPA, E-BPA-08, 20. Electrical rates are one of these factors, but electricity consumption also depends on population changes, weather, the prices of competing sources of energy, and the health of the economy. Id. Modifying Table 3 to show data on a per-customer basis would not allow any additional conclusions to be made about the responsiveness of end-use energy consumption to wholesale power rates than the table allows now, because of inability to isolate the effects of rate changes.

The same party argues that Table 8 also would be more informative if loads were shown on a per-customer basis. City of Tacoma, WP-87-7366E. The argument presented for Table 3 regarding the inability to isolate the effect of rate changes on end-use consumption also applies to the data in Table 8.

Decision

Presenting data on end-user energy consumption on a per-customer basis may be an alternative to the EA's presentation of such data on a customer class basis. However, the EA presents such data only for general information.

End-user electricity consumption is influenced by many factors other than electricity price; no conclusions about end-user response based solely on changes in rates may be made.

Issue 5

Should the EA specify causes of reduced customer consumption in each of the alternatives?

Evaluation of Positions

Two commenters state that the effects of curtailment, conservation, and fuel switching on loads are very different in their effects on energy services received by consumers. These commenters claim that the EA should specify in its analysis which combination of the three is causing the potential reduced electricity consumption shown in the EA. NCAC, WP-87-7206E; City of Tacoma, WP-87-7366E.

Quantitatively analyzing the impacts of curtailment, conservation, and fuel switching on each rate increase alternative would be difficult, as numerous factors in addition to rate levels are involved. These factors include availability of alternatives to electricity, availability of local utility programs for consumer technical assistance and conservation, consumer perceptions of fuel (or conservation) value, and economic factors. BPA, E-BPA-08, 57.

More importantly, the EA found that differences in projected loads (demand for electricity) between the alternatives do not appear to result in significant physical environmental impacts. On a regional basis, the difference in loads between the High Increase case and the No Action case is estimated to be only 4-5 percent. BPA, E-BPA-08, 40. Over half of the differences in projected loads between alternatives result from changes in direct-service industrial (DSI) loads. The EA concludes that the projected reduction in DSI load would be due to curtailment, as opposed to fuel switching. BPA, E-BPA-08, 58. The EA attributes the remainder of the potential load loss that could occur from changes in BPA's rate levels to a combination of curtailment, conservation, and fuel switching. Since the non-DSI load differences are relatively small, however, any differences in the amounts of curtailment, conservation, and fuel switching would necessarily be insignificant. Id., 58-59. The EA's analysis of the sources of potential load reductions is necessarily qualitative. It would be unreasonable to attempt to quantitatively determine the sources of potential load reductions of the relatively small magnitude projected by the EA.

Decision

It is unduly burdensome and analytically difficult, given the small magnitude of the changes in load projected for BPA's proposed rate increase

and the alternatives, for the EA to quantify specific amounts of potential load reductions which are caused by curtailment, conservation, or load switching.

Issue 6

Is the EA's presentation of price elasticity and its impacts on regional irrigators and BPA revenues accurate?

Evaluation of Positions and Decision

Two commenters contend that the irrigation elasticity study compiled by Northwest Economic Associates is incorrect. NIU, WP-87-7367E; IPUC, WP-87-7354E.

The estimates of price elasticity of irrigation loads in the EA are based upon information developed and used elsewhere in the rate filing to forecast loads. The arguments regarding elasticity and the merits of the NEA study will not be repeated here. See Moorman/Schneider, BPA, E-BPA-52, and ROD Chapters II.D. and IX.A.1.

The same parties state that the EA understates the multiplier effects and regional effects of the proposed rate increase on rate-sensitive areas. However, the EA analyzes overall revenue recovery rather than rate design. BPA, E-BPA-08, 3. BPA acknowledges the economic difficulty faced by the region's irrigators, and has proposed continuing and redesigning the discount for irrigation loads. See Chapter IX.A.1.

Issue 7

Why are socioeconomic impacts not included in the scope of the EA?

Evaluation of Positions

Two commenters discuss potential socioeconomic effects of the BPA rate increase alternatives that are examined in the EA. One participant states that the EA needs to specify its reasons for not analyzing socioeconomic effects. NCAC, WP-87-7206E. One party claims that the EA must analyze socioeconomic effects, particularly in estimating end-user responses to changes in rates. City of Tacoma, WP-87-7366E.

Council on Environmental Quality regulations state that social and economic effects need be considered as potential results of an action only when they are related to a "primary" effect on the natural and physical environment. The courts have reinforced this interpretation of NEPA. Ratesetting cannot be assumed to have a primary effect on the physical environment.

Although the EA states that an analysis of socioeconomic impacts is beyond the scope of the EA, it also acknowledges that such impacts could occur. BPA, E-BPA-08, 3. The conclusions in Chapter 3 of the EA that socioeconomic impacts in some consumer sectors could occur as a result of the alternatives examined in the EA are based on analyses presented in Environmental Impact Statements prepared by BPA for previous rate filings. For example, Chapter III.B.2. of the BPA 1983 Wholesale Power Rate Final EIS (September 1983) extensively discusses potential socioeconomic impacts on particular consumer subgroups. The 1983 Final EIS states that the effect of rising electrical rates is most severe for low-income residential consumers, industries buying electricity at retail from BPA's customer utilities, BPA's direct-service industrial customers, and some irrigating farmers. BPA, WP-83-FS-08, 33-51. As discussed in Issues 4 and 5, supra, however, reaching accurate conclusions on the effect of BPA's wholesale power rates on end-use consumers is virtually impossible because of the small magnitude of load changes due to rates and the many factors other than power rates that affect end-use consumption.

Decision

Analysis of the potential socioeconomic impacts of the rate increase alternatives examined in the EA is not required for an Environmental Assessment by the CEQ regulations that implement NEPA. Although not required to do so, BPA attributes potential socioeconomic effects to the rate alternatives throughout the EA. The conclusions in the EA regarding socioeconomic impacts are based on previous Environmental Impact Statements prepared by BPA for other rate adjustment actions.

Issue 8

How should the EA analyze the potential impacts on anadromous fish of BPA's proposed rate increase?

Evaluation of Positions

A commenter states that the EA presents no objective support for its conclusion that the alternative rate scenarios would have no significant impact on anadromous fish. The participant states that BPA should analyze such impacts. NMFS, WP-87-7345E and WP-87-7533E.

The EA examines hydro power operations for the High Increase alternative. BPA, E-BPA-08, 50. Even in this extreme case, the change in loads from the No Action alternative resulting from the change in rates was found to be inconsequential: on a regional basis, the difference in loads between the High Increase and No Action alternatives is estimated to be only 4-5 percent. BPA, E-BPA-08, 40. BPA's rate increase proposal falls between the No Action alternative and the Proposed rate alternative, which is a substantially lower assumed rate increase than the High Increase alternative. Total regional loads under the Proposed alternative are projected to be only 1 percent less in both FYs 1990 and 2000 than loads under No Action. BPA, E-BPA-08, 40. DSI loads comprise almost half of the difference. BPA, E-BPA-08, 14. Further,

DSI rates as presented in the final proposal increase over current rates much less than the increase of 10 percent under the EA's Proposed case. See ROD Chapter IX.C. This would result in differences in total regional loads from No Action which are even less than presented in the EA. BPA thus concludes that the effects of its proposed rate increase on hydro system operations would not vary substantially from effects under the No Action alternative and would be so small as to be unquantifiable. BPA, E-BPA-08, 51. Since the effects on hydro system operations would be so small, it is not possible to identify any significant impacts on fish and wildlife.

Moreover, to attribute a potential change in hydro system operations to changes in rates requires that several intervening links be made. First, a change in rates must be shown to cause a change in power demanded (load) and a resulting change in the amount of surplus firm power available to market. Second, assuming a rate increase and a resulting load decrease, the additional surplus power assumed to be made available must be sold within the constraints of BPA's markets. Third, the sale would have to be of a type of power which would cause a change in system operations. Fourth, then it would have to be shown that changes in spill and flow of water could result and could affect fish and wildlife. None of these links can be made without considerable speculation. Operating constraints of the hydro system, marketing conditions, and the future level and stability of the power rate applicable to the changed level of power sales all would affect the link between loads and hydro system operations. Therefore, because of this multitude of intervening and interacting assumptions, the impact of the rate increase in terms of fish survival is not reasonably foreseeable. Furthermore, as explained above and documented in the EA, changes in loads attributable to changes in BPA's rates are insignificant relative to the magnitude of these other uncertainties. The potential effect of wholesale rate adjustments on recreation and wildlife similarly is insignificant. BPA, E-BPA-08, 54-57.

In addition, in the 1983 Wholesale Power Rate Environmental Impact Statement (EIS), BPA was not able to determine significant differences in river operations between revenue level alternatives (see the 1983 EIS, p. VI-45).

Decision

The loads under BPA's rate proposal likely would vary from loads under the EA's No Action alternative by an insignificant amount, less than one percent. The effects on hydro system operations, and the potential resulting effects on fish and wildlife, would not vary substantially from effects under the No Action alternative and would be so small as to be unquantifiable. An analysis of potential impacts on anadromous fish of BPA's rate proposal thus would not provide useful results.

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CHAPTER XII

COMMENTS OF PARTICIPANTS

Introduction

This chapter addresses the comments of participants in BPA's 1987 rate proceeding. Participants are persons and organizations who choose not to incur the responsibilities and obligations required of parties to the rate case. Participants' comments are made part of the Official Record of the proceeding, however, the same as comments of the parties.

Participants' comments become part of the Official Record in several ways. Field hearings were held February 3-12, 1987, throughout the region. A public comment forum was held April 30, 1987, in Portland. A total of 170 persons presented their comments, orally and in writing, at these meetings. The field hearings and comment forum were transcribed and the transcriptions made part of the Official Record. BPA also received 7541 pieces of correspondence related to the rate filing during the public comment period, which officially ended May 15, 1987. These comments also became part of the Official Record.

BPA reviewed the participants' portion of the record and identified the issues to be evaluated in this chapter of the Record of Decision. Comments on specific subject areas are evaluated in the chapters that address those topics. The issues evaluated in this chapter reflect the general concerns expressed by participants. Because of the volume of comments received, the Record of Decision combines individual comments into summaries of the positions expressed. As in the rest of the rate case, comments related to program cost levels and BPA planned spending are not addressed, as they are not at issue in the rate case. See Chapter I.

A list of the participants and copies of the comments of participants are available for inspection in BPA's Public Reference Room.

Issue 1

Does BPA need a rate increase?

Evaluation of Positions

Many participants do not believe that BPA needs a rate increase. They also believe that BPA did not justify its proposed 1987 rate increases. They suggest that BPA should cut its costs rather than raise rates for electricity.

BPA sets its rates based on the directives in several Federal laws. For example, the Bonneville Project Act of 1937 requires BPA to recover through its power rates the costs to produce and transmit power, including the scheduled amortization of the Federal investment in the Federal power system in the Pacific Northwest. Similar directives are found in the Federal

Columbia River Transmission System Act of 1974 and the Flood Control Act of 1944. The Transmission Act also authorizes BPA to issue bonds and to set rates at levels that will allow BPA to repay the costs of the bonds as required.

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 requires BPA to recover, according to sound business principles, the costs of acquiring, conserving, and transmitting electric power. These costs include the amortization of the Federal investment in the Federal Columbia River Power System, for which BPA repays the U.S. Treasury. These costs also include the cost of net-billing arrangements, in which BPA pays the owners of power generation plants for certain costs of the plants. The Northwest Power Act (section 7) also describes how rates for BPA's individual customer groups should be set. See, also, BPA testimony of Melton/Meyer, WP-87-E-BPA-17, 1-2, and Chapter I of this Record of Decision.

Because of these legal requirements, over 90 percent of BPA's costs are fixed. In response to comments from its customers and others, however, several times in the last few months BPA has reduced the costs over which it has control. The reductions totaled hundreds of millions of dollars over the next two fiscal years. BPA's initial proposal was for an average increase of 13.1 percent for the Priority Firm Power rate (11.5 percent for preference customers). In supplemental testimony BPA reduced the proposed increase to 9.5 percent for the Priority Firm rate (8.5 percent for preference customers). The increase is reduced even further for the final proposal.

Some participants suggest that BPA should limit its proposed rate increase to a single-digit (less than 10 percent) increase, or limit the proposed increase to the rate of inflation. BPA is unable to target its proposed rate increases to a particular percentage, however, because BPA's rates are based on costs. Although BPA has substantially reduced its discretionary costs, most of BPA's costs are fixed and cannot be reduced. BPA's rates also allow for the risks of BPA not recovering its revenue requirement. These risks include water conditions and market conditions for surplus power. See Chapter III.

Many participants thanked BPA for giving them the chance to comment on BPA's proposed rates. Some participants, however, express skepticism about the amount of attention paid their comments. The Northwest Power Act (section 7(i)) describes a formal process that BPA must use when setting its rates. BPA developed other procedures based on those in the Act that add to BPA's responsibilities for involving interested parties and the public in its ratesetting. These procedures include notifying the public of opportunities to comment on BPA's proposed rates, and carefully considering the comments of the public when making any decision.

BPA must document its proposed rate levels and ratesetting methods. BPA's proposed rates are subject to review and comment by all parties and participants in BPA's rate case. BPA adds all comments received to the Official Record of the rate case, on which the final rate proposal is based. After the rate development proceeding is over, BPA submits its proposed rates to the Federal Energy Regulatory Commission for confirmation and approval.

The FERC reviews BPA's rates to assure that they will allow for repayment of the Federal investment in the Federal power system after first meeting BPA's other costs; that they are based on BPA's total system costs; and that transmission rates equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system.

Decision

Because of statutory requirements, BPA must set its rates to recover its costs. Most of BPA's costs are fixed. BPA has significantly reduced its planned spending for discretionary programs for the next rate period, however, in response to comments received. In addition, BPA's proposed rates are subject to review and comment by parties and participants in BPA's rate case and by the Federal Energy Regulatory Commission. BPA has adequately justified its proposed rate increases as required by law.

Issue 2

Should BPA reduce its rates to increase power sales?

Evaluation of Positions

Some participants suggest that BPA should reduce its rates so consumers would use more power, thus improving BPA's revenue recovery. Other participants believe that if BPA were to reduce power rates, more of BPA's surplus power could be sold, particularly outside the region.

As explained in the Evaluation of Positions for Issue 1 above, BPA must set its rates to recover its costs. BPA sets its rates by first forecasting the loads it must meet and the costs it must recover. Then the costs are allocated to the loads of BPA's customer classes according to statutory requirements and BPA's rate design methods.

Some participants suggest specific ratepayers that should be offered lower rates. For example, some participants believe that rates at which power is sold to California and to BPA's aluminum smelter direct-service industries and other businesses should not be reduced at the expense of the Pacific Northwest's residential ratepayers. Others believe that BPA could sell more of its surplus power by reducing rates to the aluminum smelters. As discussed earlier, BPA's rates are based on costs. Since BPA has a certain amount of costs that must be recovered, it is clear that costs allocated (by cost of service) to a particular customer class but not recovered from that customer class must be recovered from BPA's other customer classes. Such reallocation of costs can lead to claims that BPA is setting rates inequitably. The Northwest Power Act also limits BPA's ability to shift costs between customer classes by prescribing how rates for BPA's particular customer classes are to be set.

In addition, it is not clear that reducing rates to a particular customer class would result in higher electricity consumption. BPA's main concern is recovery of its revenue requirement in order to pay the Treasury on time. BPA

would have to carefully estimate how much "extra" power it would have to sell at reduced rates to increase revenues. Since BPA markets electricity at the wholesale level and consumption occurs at the retail level, in response to retail rather than wholesale electrical rates, the determination is even more difficult. Retail consumers decide how much electricity to buy based on various factors--weather, for example--of which price is only one.

BPA's recent experience with marketing outside of the Pacific Northwest shows that sales have not decreased significantly but prices and revenues have fallen drastically. The current situation is a result of relatively low oil and gas prices. California utilities can generate power at their own plants for a per-kilowatthour cost that is less than BPA's fully allocated cost of power. Thus, BPA has had to lower prices to sell power to California. This situation allows BPA to make money in the short term, but does not allow BPA to recover its costs in the long term. This situation could raise BPA's rates in the future and jeopardize BPA's payments to the U.S. Treasury.

BPA has underway an aggressive marketing effort. With help from its customers and potential customers, BPA is developing programs to market surplus power both within and outside the Pacific Northwest. BPA intends to continue working to market surplus power on a long-term basis with the goal of stabilizing BPA revenues and enhancing generation and transmission facility planning. BPA's marketing programs will consider price in concert with other marketing tools such as product design.

Decision

It is not clear that simply reducing BPA's wholesale power rates will increase power sales. Potential purchasers of any product consider many factors in addition to the price of the product. It is uncertain how the price of wholesale power from BPA would affect the amount of power purchased at the retail consumer level. And BPA must recover its costs--if not from one customer group, from another--so that it can make timely payments to the U.S. Treasury.

Issue 3

Does BPA's proposed wholesale power rate increase punish ratepayers for conserving energy?

Evaluation of Positions and Decision

Many participants state that BPA's proposed rate increase would punish them for conserving energy. Realizing that most of BPA's costs are fixed, these participants believe that BPA's programs to enable conservation have caused BPA's loads to decline, or to rise at a relatively slow rate, resulting in the necessity of rate increases to recover BPA's rising costs.

This concern of the participants is valid to only a small extent. BPA's loads have remained stable in the last few years. Conservation of energy has contributed to reducing load growth, but much less than has the depressed

economy of the Pacific Northwest. Because BPA's costs are rising, due to inflation and other causes beyond BPA's control, rates also must increase. If an individual ratepayer conserves energy, all else equal, even with rising electrical rates his power bill will be lower than if he had not conserved.

Issue 4

How does BPA's proposed rate increase reflect upon BPA, as a government agency, and its responsibility to the public?

Evaluation of Positions

Many participants state that BPA should avoid raising its power rates, and if possible reduce its rates, to avoid adverse economic effects on the people of the Northwest. They claim that BPA, as a government agency, has a responsibility to the people of the region to consider the public's welfare, especially since the economy of the Northwest is depressed. The participants point out that the prices of all services and products are rising and request that electricity prices be held stable.

The discussion of Issue 1, above, explains why BPA must periodically review and revise its rates. BPA and those who benefit from the Federal power system in the Pacific Northwest are responsible for paying the costs of that system, including the investment of the U.S. Treasury.

In past years BPA has had to reschedule amortization payments to the U.S. Treasury because revenues were lower than needed to pay BPA's other costs and make payments on time. This practice of rescheduling amortization payments has been criticized by the General Accounting Office, the Office of Management and Budget, and members of Congress.

Several participants mentioned the possibility of BPA being "privatized" as a benefit if it would make BPA more responsive to the region's ratepayers. Because of BPA's responsibility to set rates as low as possible consistent with sound business principles, and the concern of the Federal government that BPA pay its amortization on time, BPA developed a risk management strategy as part of its 1987 rate proposal. The purpose of the risk management strategy is to demonstrate to the Federal government that BPA and the Northwest are committed to making scheduled amortization payments on time and to improving the financial situation of BPA. This strategy is intended to reduce the possibility of BPA being "privatized" or required to pay its amortization on a mortgage-type schedule, either of which would raise BPA's rates much more than BPA's current proposed increase. See BPA testimony of Melton/Meyer, WP-87-E-BPA-17, 14-16.

Some participants suggest that BPA's proposed risk management strategy is poorly timed. They suggest that the strategy is intended to mitigate future risk that is only potential, while it is certain that the regional economy is depressed now and ratepayers would be harmed by the proposed rate increase. BPA's Risk Assessment Analysis (discussed in Chapter III.B. of this ROD) quantifies the risks BPA foresees for its revenues. As expained above, if BPA

does not address these risks, rates could be higher in the future than BPA has proposed in this rate case. Also, one of the component measures of BPA's risk management strategy, the Cost Recovery Adjustment Clause, takes effect only if revenues are significantly above or below those forecasted. Thus, a rate increase or decrease resulting from the "triggering" of the Clause is not certain or expected at this time.

Some participants are concerned that BPA's proposed rate increase is the result of greed or BPA's abuse of "monopoly power." BPA is not allowed to profit from its operations--costs of producing and transmitting power must be recovered, but no more. As a Federal Power Marketing Agency, BPA cannot be considered a monopoly, as its purpose is simply to market power for the benefit of the region at rates as low as possible consistent with sound business principles. In addition, some participants point out sources of competition to BPA as a supplier of wholesale electricity, ranging from water heater load management programs to purchasing wholesale electricity from British Columbia Hydro.

Decision

BPA's proposed rate increase is required by law. The proposed rate increase is designed to allow BPA to recover its costs, including the repayment of amortization to the U.S. Treasury. Rates are set as low as possible consistent with sound business principles. BPA's risk management package is intended to demonstrate to the Federal government that BPA and the region are committed to repaying the Treasury and to improving BPA's financial position, while keeping rates as low as possible initially. These proposed actions in the long run will keep rates as low as possible to BPA's customers, which in turn should keep rates as low as possible to the region's ratepayers.

Issue 5

Does BPA's proposed rate increase cause health problems to the people of the region from air pollution?

Evaluation of Positions and Decision

Some participants claim that BPA's proposed rate increase could cause health problems by encouraging the use of woodstoves and other sources of indoor and outdoor combustion air pollution. The health problems identified include allergies and heart and respiratory distress.

BPA's Environmental Assessment (EA) for the 1987 Initial Rate Proposal (WP-87-E-BPA-08) examines the potential environmental effects of three cases--not raising BPA's rates; raising the rates 10 percent; and raising the rates 35 percent. No significant differences were found between the three cases in the amount of electricity that could be expected to be used by retail consumers. Thus no change from present levels of air pollution would be expected as a result of BPA's proposed rate increases. See the EA, especially pages 25-26 and 34-36, and the Finding of No Significant Impact, WP-87-FS-BPA-09. See, also, Chapter XI of the ROD. Also, BPA is considering

a program for the displacement of woodstoves by electric heat as part of its consumer marketing program ("The Bonneville Partnership").

Issue 6

Should BPA design its rates based on the results of the Marginal Cost Analysis?

Evaluation of Positions and Decision

One participant questions why BPA's rates should include demand charges, since BPA has surplus generating capacity.

BPA designs its rates based on the results of the Marginal Cost Analysis (WP-87-FS-BPA-04). BPA bases its rate design on marginal cost principles to provide its customers with economically correct price signals. The Marginal Cost Analysis calculates the capacity and energy components of generation cost. The calculation shows that the marginal cost of future generation capacity on BPA's system is greater than zero. BPA's wholesale power rates include demand charges to reflect this marginal cost of capacity. See the Marginal Cost Analysis and Chapter V of the ROD.

One participant, a ratepayer, states that rates that are uniform over the year would be more equitable than seasonal rates. This participant believes that rates should not be higher in the winter peak period, when consumers must heat their homes, than in the summer.

Consideration of BPA's surplus of firm power in the Marginal Cost Analysis results in demand charges for wholesale power that do not vary by season. See the Marginal Cost Analysis (WP-87-FS-BPA-04), and the Wholesale Power Rate Development Study (WP-87-FS-BPA-06). Although capacity costs do not vary by season, costs of energy at the wholesale level vary by season due to BPA's dependence on energy produced from hydro storage. See the Wholesale Power Rate Development Study, and Chapter VII.F. of the ROD. Basing rates on cost of service is common ratemaking practice; it is equitable to recover the costs of a service from the customers who cause the costs to be incurred. Although BPA's rates are designed to provide economically correct price signals, BPA sets rates for wholesale power and has no control over how its customer utilities pass BPA's rate design through to their own customers (ratepayers). Many utilities use "budget plans" that allow ratepayers to pay uniform bills across the year, which negates BPA's price signals but stabilizes the budgets of both ratepayers and utilities.

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CHAPTER XIII

CONCLUSION

BPA's rates have been set to recover the costs associated with the production, acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System over a reasonable period of years, and other costs and expenses incurred in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be as low as possible consistent with sound business principles and to encourage the widest possible use of electricity.

In performing their duties under section 7(i) of the Northwest Power Act, the Hearing Officers have assured that a full and fair evidentiary hearing, open to all interest parties and participants, has been conducted on all issues relevant to BPA's wholesale power and transmission rates. All parties have been given every reasonable opportunity to engage in discovery, present testimony, engage in cross-examination of adverse witnesses, present oral argument, and submit briefs.

Based upon the record of this proceeding, I hereby adopt the attached wholesale power and transmission rate schedules as Bonneville Power Administration's final rates.

Issued at Portland, Oregon, this 29th day of July 1987.

James J. Jura
Administrator

APPENDICES

APPENDIX A

List of Parties and Abbreviations

Association of Northwest Gas Utilities	NGU
Association of Public Agency Customers	APAC
Atlantic Richfield Company	ARCO
Bonneville Power Administration	BPA
CP National Corporation	CPN
California Energy Commission	CEC
California Public Utilities Commission	CPUC
Cascade Steel Rolling Mills, Inc.	CSRM
Chelan County PUD No. 1	Chelan
Columbia Falls Aluminum Compnay	CFAC
Columbia River Inter-Tribal Fish Commission	CRITFC
Cowlitz County PUD No. 1	Cowlitz Co.
Direct Service Industries	DSIs
Douglas County PUD No. 1	Douglas Co.
Dow Corning Corporation	Dow Corning
Eugene Water & Electric Board	EWEB
Forelaws Project	Forelaws
Grant County PUD No. 2	GRT
Idaho Cooperative Utilities Assocation, Inc.	ICUA
Idaho Power Company	IPC
Intalco Aluminum Company	Intalco
Montana Power Company	MPC
National Marine Fisheries Service	NMFS
Non-Generating Public Utilities	Nongenerating
Northwest Investor-Owned Utilities (one or more of the following: Pacific Power & Light Company, Puget Sound Power & Light Company; Portland General Electric Company; Montana Power Company; Utah Power Company; Idaho Power Company; the Washington Water Power Company)	IOUs
Northwest Irrigation Utilities	NIU
Northwest Parties (Public Generating Pool, Public Power Council, Portland General Electric Company and the Association of Public Agency Customers)	NWP
Oregon Farm Bureau Federation	OFBF
Oregon Public Utility Commissioner	OPUC
Pacific Carbide and Alloys Company	PCAC
Pacific Northwest Generating Company	PNGC
Pacific Power & Light Company	PP&L
Portland General Electric Company	PGE
Public Generating Pool	PGP
Public Power Council	PPC
Puget Sound Power & Light Company	PSP&L

Seattle City Light	SCL
Tacoma City Light	TCL
Utah Power & Light Company	UP&L
Washington Utilities and Transportation Commission	WUTC
Washington Water Power Company	WWPC
Western Montana Electric Generation and Trans. Cooperative, Inc.	WMEGTC
Western Public Agencies Group	WPAG
Wyoming Public Service Commission	WPUC

APPENDIX B

WHOLESALE POWER RATE SCHEDULES

and

GENERAL RATE SCHEDULE PROVISIONS

WHOLESALE POWER RATE SCHEDULES

and

GENERAL RATE SCHEDULE PROVISIONS

WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

TABLE OF CONTENTS

Wholesale Power Rate Schedules		Page
PF-87	Priority Firm Power Rate	B1
IP-87	Industrial Firm Power Rate	B8
VI-87	Variable Industrial Power Rate	B12
SI-87	Special Industrial Power Rate	B20
CF-87	Firm Capacity Rate	B25
CE-87	Emergency Capacity Rate	B27
NR-87	New Resource Firm Power Rate	B29
SP-87	Short-Term Surplus Firm Power Rate	B35
SL-87	Long-Term Surplus Firm Power Rate	B37
NF-87	Nonfirm Energy Rate	B39
SS-87	Share-the-Savings Energy Rate	B44
RP-87	Reserve Power Rate	B46

General Rate Schedule Provisions		
Section I	Adoption of Revised Rate Schedules and General Rate Schedule Provisions	B51
Section II	Types of BPA Service	B51
Section III	Billing Factors and Billing Adjustments	B54
Section IV	Other Definitions	B71
Section V	Application of Rates under Special Circumstances	B78
Section VI	Billing Information	B81
Section VII	Variable Industrial Rate Parameters and Adjustments	B84

SCHEDULE PF-87

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, construction, test and start-up, and station service.

Utilities participating in the exchange under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

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

This schedule supersedes Schedule PF-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers and includes credit attributed to the provision of section 7(b)(2) of the Northwest Power Act. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge

a. $3.46 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 18.4 mills per kilowatthour of billing energy for the billing months September through March;

b. 14.4 mills per kilowatthour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge

a. $3.56 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 19.1 mills per kilowatthour of billing energy for the billing months September through March;

b. 15.1 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) the Measured Demand, before adjustment for power factor.

b. the lower of:

(1) the Computed Peak Requirement, or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 78 percent of the Measured Energy (excluding unauthorized increase), and

(2) 22 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 57 percent of the Measured Energy (excluding unauthorized increase), and

(2) 43 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

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

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase or decrease calculated in section III.C.5.c and III.C.5.d of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the PF rates due to the Cost Recovery Adjustment Clause. An additional decrease of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage decrease in the PF rates due to the Cost Recovery Adjustment Clause.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an unauthorized increase. BPA first shall determine the amount of unauthorized increase related to demand and shall treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, which exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

(1) to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

H. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

I. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that

purchaser's computed peak requirement and computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October;

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF-87 rate is 78.5 percent FBS and 21.5 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE IP-87

INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule the IP-87 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser's Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium Rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard Rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of Service.

A. Demand Charge

1. $4.14 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 19.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 15.6 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs). If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-87 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI's load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.6 mills per kilowatthour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance

includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs and shall be applied to all power purchases under this rate schedule.

Application of the Cost Recovery Adjustment Clause shall result in a uniform adjustment applied to the demand and energy charges, contained in sections II.A and II.B of this rate schedule, and the first quartile discount, if applicable, contained in section IV.A.1 of this rate schedule. A uniform adjustment will be made only if it causes demand and energy charges and the first quartile discount to increase. No downward adjustment resulting from the Cost Recovery Adjustment Clause shall be made to any portion of this rate schedule.

The uniform percentage (CRAC%) determined in section III.C.5.c.(1) of the GRSPs shall be applied in the following manner:

$$\left(1 + \frac{\text{CRAC\%}}{100}\right) * \frac{22.8}{23.5}$$ times the demand, energy, and first quartile discount charges.

where: 22.8 represents the average IP-87 margin-based rate in mills per kilowatthour, and 23.5 represents the average IP-87 floor rate in mills per kilowatthour.

D. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

E. Power Factor Adjustment

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

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE VI-87

VARIABLE INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for purchases under the Power Sales Contract implementing the Variable Industrial Power rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated General Rate Schedule Provisions (GRSPs) in the Variable Rate Contract, DSIs electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Section VI.J. supplements schedule VI-86. GRSPs effective July 1, 1985, as revised effective August 1, 1986, and as revised in the 1987 rate case and in subsequent wholesale rate filings are applicable to this rate schedule. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. TERM OF THE RATE

This rate schedule shall take effect on August 1, 1986, and shall terminate on midnight June 30, 1993, unless BPA elects to exercise its unilateral option to terminate the rate at midnight June 30, 1991. This termination right is described in section VI.E. of this rate schedule. Actions to invoke an early termination shall comply with section VI.E. of this rate schedule and with the provisions and stipulations set forth in the Variable Rate Contract.

SECTION III. RATE

A. Revised Rate Charges Subject to Rate Case Adjustments

The following rates shall apply to Industrial customers that meet the eligibility requirements and elect to purchase power under the Variable Industrial Power Rate Schedule. These rates snall remain in effect until the next Rate Adjustment Date, at which point the rates shall be adjusted following the procedures set forth in section VI.C. of this rate schedule, unless the Cost Recovery Adjustment Clause triggers, at which point the rates shall be adjusted following the procedures set forth in section VI.J of this rate schedule. In addition, the Lower Rate Limit also will be subject to a biennial adjustment pursuant to section VI.B. of this rate schedule. The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by purchasers of Industrial Firm Power is

not contained in this rate schedule; the value of reserves credit has been included in the determination of the Plateau Energy Charge.

1. Base Variable Industrial Rate

   a. Demand Charge

      $5.33 per kilowatt of billing demand occurring during the Peak Period. No demand charge is applied during Offpeak Period hours.

   b. Plateau Energy Charge

      16.1 mills per kilowatthour of billing energy.

2. First Quartile Service Discount

   0.5 mills per kilowatthour of billing energy.

3. Lower Rate Limit

   8.3 mills per kilowatthour of billing energy.

4. Upper Rate Limit

   21.9 mills per kilowatthour of billing energy.

B. Initial Rate Parameters Subject to Annual Adjustments

The following rate parameters shall be used in determining the power bills for customers electing to purchase power under the Variable Industrial Power rate schedule. These parameters will be adjusted annually starting on July 1, 1987, and every July 1 thereafter, in accordance with the procedures contained in section VII.B. of the GRSPs.

1. Lower Pivot Aluminum Price

   60.8 cents per pound.

2. Upper Pivot Aluminum Price

   73.4 cents per pound.

SECTION IV. FORMULA

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.

A. Demand Charge

1. The Demand Charge, as stated in section III.A.1.a. of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. Plateau Energy Charge

When the monthly billing aluminum price (described in section VII.A. of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1. and III.B.2. of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b. of this rate schedule.

2. Reductions to Plateau Energy Charge

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP - MAP)*(LS)

where:

LP = the Lower Pivot Aluminum Price as stated in section III.B.1. of this rate schedule.

MAP = the monthly billing aluminum price in cents per pound determined pursuant to section VII.A. of the GRSPs.

$$LS = \text{lower slope} = \frac{1 \text{ mill per kilowatthour}}{1 \text{ cent per pound}}$$

or

b. the Lower Rate Limit as stated in section III.A.3. of this rate schedule.

3. Increases to Plateau Energy Charge

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge + (MAP - UP)*(US)

where:

MAP = the monthly billing aluminum price in cents per pound, as determined according to section VII.A. of the GRSPs.

UP = the Upper Pivot Aluminum Price as stated in section III.B.2. of this rate schedule.

$$US = \text{upper slope} = \frac{0.75 \text{ mills per kilowatthour}}{1 \text{ cent per pound}}$$

or

b. the Upper Rate Limit, as stated in section III.A.4. of this rate schedule.

SECTION V. BILLING FACTORS

A. Billing Demand

1. Billing Demand for Customers Whose Entire BPA Load is Served at the Variable Industrial Power Rate

The billing demand for power purchased shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the GRSPs.

2. Billing Demand for Customers When Only a Portion of Their Total BPA Load is Served at the Variable Rate

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

3. Billing Demand During Periods of Transitional Service

If BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

SECTION VI. OTHER ADJUSTMENTS AND SPECIAL PROVISIONS

A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B of the rate schedule shall be adjusted following the procedures set forth in section VII.B of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B of the rate schedule. The revised Lower and Upper Pivot Aluminum Prices shall be used for billing purposes and subsequent adjustments to the Lower and Upper Pivot Aluminum Prices.

B. Lower Rate Limit

Beginning with the July 1, 1988 annual adjustment date and every second July 1 thereafter, the Lower Rate Limit as stated in section III.A.3. shall be increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall supersede the Lower Rate Limit as stated in section III.A.3 of the rate schedule. This increase is in addition to rate adjustment increases in the Lower Rate Limit described in section VI.C of this rate schedule. In the event that a rate adjustment date and the annual adjustment date occur simultaneously, the Lower Rate Limit shall be adjusted first for changes in the Plateau Energy Charge pursuant to section VI.C. of this rate schedule, and then increased by 1 mill per kilowatthour. The revised Lower Rate Limit shall be used for billing purposes and subsequent rate adjustments.

C. Rate Adjustments

The overall rate level of this rate shall be subject to adjustment in BPA's general wholesale power rate case following the procedures and directives of the Northwest Power Act. The overall rate level consists of the Demand Charge, Plateau Energy Charge, and First Quartile Service Adjustment contained in sections III.A.1 and III.A.2; these shall be adjusted by a uniform percentage based on the percentage change in the overall rate level. The Lower and Upper Rate Limits as stated in sections III.A.3 and III.A.4 of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, in the Plateau Energy Charge. The Lower and Upper Pivot Aluminum Prices shall not be adjusted in the rate case; rather, they shall be adjusted pursuant to the procedures described in section VII.B of the GRSPs. The lower and upper slopes shall not be adjusted. The rate for unauthorized increase shall be separately determined in each rate case.

D. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus FELCC, a discount contained in section III.A.2 of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B. for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to

unauthorized increase charges under section VI.G of this rate schedule. To qualify for the First Quartile Discount, the purchaser mustrequest discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

E. Termination Provision

The Administrator may terminate the Variable Industrial Power rate effective midnight June 30, 1991, upon a determination that significant changes in the conditions and expectations under which this rate was offered render the continuation of the Variable Industrial rate inconsistent with BPA's stated goals and objectives. BPA shall provide notification of such a determination pursuant to the provisions of the Variable Rate Contract. As part of the notification procedures, BPA shall provide a reasonable opportunity for interested parties to comment on BPA's determination, as well as to examine the comments submitted by other parties, prior to BPA taking final action to cancel the rate. If BPA determines that the Variable Industrial rate will remain in place until midnight June 30, 1993, BPA shall provide notice that so states and no additional action by BPA will be required.

F. Curtailments

BPA shall charge the customer for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract and the provisions contained in the Variable Rate Contract.

G. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

H. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average

lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the BPA Operating Level by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

I. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI to whom BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

J. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all power purchases under this rate schedule consistent with the procedures to adjust the Variable Industrial rate and the provisions of the Variable Rate Contract. A uniform adjustment will be made only if it causes demand and Plateau Energy charges and the First Quartile Service Discount to increase. No downward rate adjustment resulting from the Cost Recovery Adjustment Clause shall be made to any portion of this rate schedule.

The uniform percentage (CRAC%) determined in section III.C.5.c.(1) of the GRSPs shall be applied in the following manner:

$$\left(1 + \frac{\text{CRAC\%}}{100}\right) * \frac{22.4}{23.0}$$

times the demand and Plateau Energy charges contained in section III.A.1 of this rate schedule and to the First Quartile Service Discount specified in section III.A.2 of this rate schedule.

where: 22.4 represents the average VI-87 margin-based plateau rate in mills per kilowatthour, and 23.0 represents the average VI-87 floor rate in mills per kilowatthour.

The Lower and Upper Rate Limits stated in sections III.A.3 and III.A.4 of this rate schedule shall be adjusted by an amount equal to the change, in mills per kilowatthour, to the Plateau Energy charge due to application of the Cost Recovery Adjustment Clause. The adjusted rate parameters shall be used for billing purposes and supersede the rate charges subject to the adjustment contained in section III.A of this rate schedule. The adjusted rate parameters shall also be used in subsequent rate adjustments pursuant to section III.B of this rate schedule and to subsequent biennial

adjustments to the lower rate limit pursuant to section VI.B of this rate schedule.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the VI-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SI-87

SPECIAL INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. The Special Industrial Offpeak rate available for Hanna Nickel Smelting Company pursuant to the Amendatory Agreement executed July 1, 1985, remains in force and is retained herein. Except for the Special Industrial Offpeak rate, schedule SI-87 supersedes schedule SI-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule contains the Standard Special Industrial Power Rate and the Special Industrial Offpeak Rate. The Standard Special Industrial Power Rate is available to any qualifying DSI for full service provided during all hours of the day. The Special Industrial Offpeak Rate is a lower rate available to the Hanna Nickel Smelting Company (Hanna) for service during periods specified by BPA. A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Standard Special Industrial Power Rate.

A. Standard Special Industrial Power Rate

1. Demand Charge

   a. $3.08 per kilowattmonth of billing demand occurring during all Peak Period hours.

   b. No demand charge during Offpeak Period hours.

2. Energy Charge

   a. 16.9 mills per kilowatthour of billing energy for the billing months September through March;

   b. 12.9 mills per kilowatthour of billing energy for the billing months April through August.

B. Special Industrial Offpeak Rate

1. Demand Charge

No demand charge in any hour of the day.

2. Energy Charge

7.0 mills per kilowatthour of billing energy during all billing months.

SECTION III. BILLING FACTORS

A. Billing Demand

1. Standard Special Industrial Power Rate

The billing demand for power purchased under the Standard Special Industrial Power Rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs).

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

2. Special Industrial Offpeak Rate

There is no billing demand for purchases under the Special Industrial Offpeak rate.

B. Billing Energy

The billing energy under both the Standard Special Industrial and Special Industrial Offpeak Rates shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

The kilowatthours of billing energy shall be prorated among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE SI-87 RATE FOR THE HANNA NICKEL SMELTING COMPANY

All purchasers, except for Hanna, shall purchase power under the Standard Special Industrial Power rate. Hanna shall have the option to select one of two types of service, standard service or offpeak service. In this case, BPA will provide standard service under the Standard Special Industrial Power Rate and offpeak service under the Special Industrial Offpeak Rate. Unless BPA receives a formal request from Hanna for service under the Special Industrial Offpeak Rate, all service will be standard service provided under the Standard Special Industrial Power Rate. To change the type of service provided and the associated rate, Hanna shall submit a formal request for service under the preferred rate option in accordance with the terms of the power sales contract providing for purchases under this rate schedule. Once Hanna has elected to purchase under one of the two options, all purchases of Special Industrial Power shall be subject to the terms and conditions of that rate option until such time that Hanna requests the other type of service.

SECTION V. SERVICE UNDER THE SPECIAL INDUSTRIAL OFFPEAK RATE

BPA shall designate the hours during which offpeak service will be available, and shall provide at least 2 weeks' notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If Hanna has elected to be served under the Special Industrial Offpeak Rate, Hanna may request, during the designated offpeak periods, service in an amount not to exceed the purchaser's Contract Demand. During all other hours Hanna shall curtail service to a level not to exceed 15 percent of Contract Demand.

SECTION VI. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI's power sales contract. Any curtailment charge levied shall be computed using the Standard Special Industrial Power Rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that

clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

If BPA is providing service to Hanna under the Special Industrial Offpeak Rate, the amount by which Hanna's Measured Demand exceeds 15 percent of its Contract Demand during any hour other than the specified special hours shall be considered unauthorized increase.

C. Power Factor Adjustment

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

To make the power factor adjustment for service under the Standard Special Industrial Power Rate, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the Special Industrial Offpeak Rate, BPA shall increase the billing energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. In addition, no credit shall be applied to purchases under the Special Industrial Offpeak Rate. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

E. Extended Service Provision

The terms of this rate schedule may be extended for a period not to exceed June 30, 1990, in accordance with the Amendatory Agreement effective July 1, 1985, with the Hanna Nickel Smelting Company (Hanna). The Amendatory Agreement contains Hanna's agreement to make certain investments in a wet screening process at its Riddle facility.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SI-87 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CF-87

FIRM CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of Firm Capacity without energy on a Contract Demand basis. This schedule is available only to those purchasers holding Firm Capacity contracts executed prior to July 1, 1985. It supersedes Schedule CF-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

$42.48 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.54 per kilowattmonth of Contract Demand.

SECTION III. BILLING FACTORS

The billing demand shall be the Contract Demand.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the General Rate Schedule Provisions (GRSPs) and subsequent to any other rate adjustments.

B. Extended Peaking Surcharge

The monthly capacity rate specified in section II above shall be increased by the following extended peaking surcharge to compensate BPA for each hour that the purchaser's monthly demand duration exceeds 8 hours:

1. $0.0908 per kilowatt per hour of extended peaking for the months April through October;

2. $0.0512 per kilowatt per hour of extended peaking for the months November through March.

The charge shall be adjusted pro rata for each portion of an hour of extended peaking supplied to the purchaser.

The purchaser's monthly demand duration shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by

2. the purchaser's Contract Demand for such month.

The purchaser's extended peaking shall be the amount by which the purchaser's monthly demand duration exceeds 8 hours. The extended peaking surcharge shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

C. Energy Return Surcharge

The energy associated with the delivery of Firm Capacity must be returned to BPA in accordance with the terms of the purchaser's Firm Capacity Contract. Unless waived by BPA, any purchaser whose energy returns during any single hour exceed 60 percent of the purchaser's Contract Demand during any single hour shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months April through October, and

2. 1.48 mills per kilowatthour for the months November through March.

D. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases under this rate schedule. The percentage increase or decrease calculated in sections III.C.5.a and III.C.5.b of the GRSPs shall be applied to the demand charges contained in sections II.A and II.B of this rate schedule.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CF-87 rate is 75.1 percent FBS and 24.9 percent Exchange for contract year service.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CE-87

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of capacity:

A. when an emergency exists on the purchaser's system, or

B. when the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load, provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

$1.06 per kilowatt of demand per calendar week or portion thereof.

B. Intertie Charge

The demand charge specified above shall be increased by $0.15 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CE-87 rate is 75.1 percent FBS and 24.9 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NR-87

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $4.13 per kilowatt-month of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 25.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 21.2 mills per kilowatthour of billing energy for the billing months April through August;

SECTION III. BILLING FACTORS

In this section billing factors are listed for computed requirements purchasers (section III.A) metered requirements purchasers, and those purchasers not covered by section III.A. (section III.B.).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement;

(2) the Measured Demand, before adjustment for power factor; or

b. the lower of:

(1) the Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 56 percent of the Measured Energy, and

(2) 44 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 39 percent of the Measured Energy, and

(2) 61 percent of the Computed Energy Maximum.

B. Metered Requirements Purchasers and Other Purchasers Not Covered By Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

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

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase or decrease calculated in section III.C.5.a and II.C.5.b of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the NR rates due to the Cost Recovery Adjustment Clause. An additional decrease of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage decrease in the NR rates due to the Cost Recovery Adjustment Clause.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) to a class of power that BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such month,

shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

F. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

G. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's estimated computed peak requirement and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October, and

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR-87 rate is 100.0 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SP-87

SHORT-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Surplus Firm Power for the period ending September 30, 1992, including purchases under the Western Systems Power Pool (WSPP) agreements. BPA is not obligated to make power or energy available under this rate schedule if such power or energy would displace sales under the IP-87, VI-87, PF-87, or NR-87 rate schedules. Schedule SP-87 supersedes schedule SP-85 and associated GRSPs, except in the case of contracts for sales under schedule SP-85 which become effective on or before September 30, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Contract Rate

1. Demand Charge

a. For contracts that specify 12 months of service per year, $51.48 per kilowatt per year of Contract Demand billed monthly at the rate of $4.29 per kilowatt of Contract Demand occurring during all Peak Period hours in each billing month.

b. For contracts that specify service for fewer than 12 months per year, the monthly demand charge shall be assessed only for the specified service months at the rate of $4.29 per kilowatt of Billing Demand occurring during the Peak Period plus:

$$\frac{\$4.29^{*}\ (12 - \text{specified service months})^{*}\ .25}{\text{specified service months}}$$

c. No demand charge during Offpeak Period hours

2. Energy Charge

24.3 mills per kilowatthour of Billing Energy.

B. Flexible Rate

Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA's highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.

C. Intertie Charge

Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.

1. $.36 per kilowatt per month of billing demand and

2. 0.69 mills per kilowatthour of billing energy.

Rates in section II.B having an energy-only charge that equals or exceeds 30.2 mills per kilowatthour shall be increased by 1.2 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

SECTION III. BILLING FACTORS

The billing factors shall be the Measured Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for Short-Term Surplus Firm Power on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SP-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SL-87

LONG-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available for the long-term purchase of Surplus Firm Power and Firm Displacement Power under BPA contracts. This rate schedule shall be offered for an amount of purchases not to exceed 1350 MW peak and 725 MW average, less purchases under the SCE-86 rate schedule. This rate schedule shall not be available for contracts that obligate BPA to acquire energy resources to support the sale. Schedule SL-87 supersedes schedule FD-85 and associated GRSPs except in the case of contracts for sales under FD-85 that become effective on or before September 30, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The rate for the long-term purchase of Surplus Firm Power and Firm Displacement Power shall be mutually agreed by the parties, provided that the present value of the forecasted revenue under the contract rate, as projected for the contract term at the date of contract execution, shall be equal to or greater than the forecasted revenue under the Floor projection, specified in subsection A below, and less than or equal to the forecasted revenue under the Ceiling projection, specified in subsection B below.

A. FLOOR PROJECTION

For firm power sales, the Floor projection shall be the greater of BPA's average Priority Firm rate or BPA's opportunity cost of surplus firm power, as projected for each year of the contract term in accordance with section IV.D. of the GRSP's. The average PF rate or successor rate(s) shall be calculated at the load factor of the proposed sale and assume a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales in the relevant rate case.

For firm capacity sales, the Floor projection shall be the Priority Firm demand charge, as projected for each year of the contract term in accordance with section IV.D. of the GRSP's.

B. CEILING PROJECTION

The ceiling projection for firm power sales shall be the fully-allocated cost of BPA's highest cost resource including transmission costs, as projected for each year of the contract term in accordance with section IV.D. of the GRSP's. For firm capacity sales, the ceiling projection shall be the demand component of BPA's highest cost resource including transmission costs, as projected.

SECTION III. BILLING FACTORS

The billing factors shall be the Contract Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for the long-term purchase of Surplus Firm Power and Firm Displacement Power on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SL-87 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NF-87

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF-87 supersedes Schedule NF-85 which went into effect on an interim basis on July 1, 1985, and was subsequently revised on an emergency basis and approved on an interim basis on May 1, 1986. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The average cost of nonfirm energy is 18.0 mills per kilowatthour. The NF-87 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 21.6 mills per kilowatthour.

B. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

C. Incremental Rate

The Incremental rate is the Incremental Cost of energy plus 2.0 mills per kilowatthour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

D. Contract Rate

The Contract rate is 14.9 mills per kilowatthour of billing energy.

SECTION III. ADJUSTMENTS TO RATES

A. Guaranteed Delivery Surcharge

A surcharge of 2.0 mills per kilowatthour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

Rate offers, under any of the rates specified above, greater than or equal to 18.0 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie.

SECTION IV. BILLING FACTORS

The billing energy for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

SECTION V. APPLICATION AND ELIGIBILITY

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a combination of these rates may be in effect.

A. Standard Rate

The Standard rate:

1. is available for all purchases of nonfirm energy; and

2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the power sales contract.

B. Market Expansion Rate

1. Application of the Market Expansion rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity, or

b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

a. shutdown or reduction of the output of the displaceable resource in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion rate

a. When only one Market Expansion rate is offered:

Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.0 mills per kilowatthour.

b. When more than one Market Expansion rates are offered:

Purchasers qualifying under section V.B.2. who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power

under the Market Expansion rate if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below purchaser's qualifying decremental cost minus 4.0 mills per kilowatthour.

C. Incremental Rate

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. that BPA may at its option not produce or purchase; and

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.0 mills per kilowatthour.

D. Contract Rate

The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for the sale of nonfirm energy; or

2. for determining the value of energy.

E. Western Systems Power Pool Transactions

BPA may make available nonfirm energy for transactions under the Western Systems Power Pool (WSPP) agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and shall be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside that agreement.

F. End-User Rate

BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION VI. DELIVERY

A. Rate of Delivery

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation or transmission losses.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 99.6 percent FBS and 0.4 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SS-87

SHARE-THE-SAVINGS RATE

SECTION I. AVAILABILITY

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS-87 supersedes Schedule SS-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C. of the GRSPs or lower than one mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings Rate contract.

SECTION IV. APPLICATION AND ELIGIBILITY

A. General Requirements

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. have executed a contract specifying application of the Share-the-Savings Rate Schedule.

2. have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable purchase of electricity to qualify for this rate.

B. BPA Service Priority

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions setforth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SS-87 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE RP-87

RESERVE POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of power:

A. in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;

B. for which BPA determines no other rate schedule is applicable; and

C. to serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP-85 which went into effect on an interim basis on July 1, 1985. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $3.64 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

25.3 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

B. Billing Energy

The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

SECTION IV. POWER FACTOR ADJUSTMENT

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

To make the power factor adjustment, BPA shall increase the billing demand by one percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The RP-87 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS

	Page
I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions	B51
A. Approval of Rates	B51
B. General Provisions	B51
II. Types of BPA Service	B51
A. Priority Firm Power	B51
B. New Resource Firm Power	B52
C. Industrial Firm Power	B52
D. Special Industrial Power	B53
E. Auxiliary Power	B53
F. Firm Capacity	B53
G. Surplus Firm Power	B53
H. Nonfirm Energy	B53
I. Reserve Power	B54
J. Firm Displacement Power	B54
III. Billing Factors and Billing Adjustments	B54
A. Billing Factors for Demand	B54
1. Measured Demand	B54
a. Metered Demand	B55
b. Scheduled Demand	B55
2. Ratchet Demand	B56
3. Contract Demand	B56
4. Computed Peak Requirement	B56
5. Computed Average Energy Requirement	B56
6. Operating Demand	B57
7. Curtailed Demand	B57
8. Restricted Demand	B57
9. Auxiliary Demand	B57
10. BPA Operating Level	B58
B. Billing Factors for Energy	B59
1. Measured Energy	B59
a. Metered Energy	B59
b. Scheduled Energy	B59
2. Computed Energy Maximum	B60
3. Contract Energy	B60
C. Billing Adjustments	B60
1. Power Factor Adjustment	B60
2. Outage Credit	B60
3. Low Density Discount	B61
a. Basic LDD Principles	B61
b. Eligibility Criteria	B62
c. Discounts	B63
4. Irrigation Discount	B63
a. Basic Irrigation Discount Principles	B63
b. Qualifying Energy Purchases	B63

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS (Cont.)

		Page
	c. Initial Reporting Requirements	B64
	d. Annual Report Requirements	B64
	5. Cost Recovery Adjustment Clause	B65
	a. Terms and Conditions	B65
	b. Cost Recovery Adjustment Formula	B66
	c. Application if CRV is Negative	B66
	d. Application if CRV is Positive	B67
	e. Application to Irrigation Discount	B68
	f. Cost Recovery Adjustment Clause Implementation Process	B69
	6. Coincidental Billing Adjustment	B70
	7. Conservation Surcharge	B70
D.	Billing-Related Definitions	B71
	1. Peak Period	B71
	2. Offpeak Period	B71
IV.	Other Definitions	B71
A.	Computed Requirements Purchasers	B71
	1. Designation as a Computed Requirements Purchaser	B71
	2. Purpose of the Computed Requirements Designation	B71
B.	Definitions Relating to Nonfirm Energy	B72
C.	NF Rate Cap	B72
	1. Application of the NF Rate Cap	B72
	2. Monthly Notification of NF Rate Cap	B72
	3. NF Rate Cap Formula	B73
	4. Determination of BASC	B73
	5. Determination of Decremental Fuel Cost	B73
	6. California Gas Price	B74
	7. California Petroleum Price	B75
	8. Weighting Factors	B76
	a. Historical Gas Use in California	B76
	b. Historical Petroleum Use in California	B77
D.	Determination of SL Floor and Ceiling Rates	B78
V.	Application of Rates Under Special Circumstances	B78
A.	Energy Supplied for Emergency Use	B78
B.	Construction, Test and Start-up, and Station Service	B79
C.	Application of Rates During Initial Operation Period-Transitional Service	B79
	1. Eligibility for Transitional Service	B79
	2. Calculation of the Daily Demand	B79
	3. Billing for Transitional Service	B80
D.	Changes in a DSI's BPA Operating Level	B80
E.	Restriction of Deliveries	B80

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS (Cont.)

		Page
VI.	Billing Information	B81
	A. Determination of Estimated Billing Data	B81
	B. Load Shift and Outage Reports	B81
	C. Billing for New Large Single Loads	B81
	D. Determination of Measured Demand	B82
	E. Determination of Measured Energy	B82
	F. Billing Month	B82
	G. Payment of Bills	B82
	1. Computation of Bills	B83
	2. Estimated Bills	B83
	3. Due Date	B83
	4. Late Payment	B83
	5. Disputed Billings	B83
	6. Revised Bills	B84
VII.	Variable Industrial Rate Parameters and Adjustments	B84
	A. Monthly Average Aluminum Price Determination	B84
	1. Calculation of the Monthly Billing Aluminum Price	B84
	2. Notification of the Monthly Average Aluminum Price	B84
	3. Changes in Aluminum Price Indicators	B85
	B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices	B85
	1. Implementation Procedures	B85
	2. Annual Adjustment Procedures	B86
	a. Annual Adjustment of the Lower Pivot Aluminum Price	B86
	b. Annual Adjustment of the Upper Pivot Aluminum Price	B86
	3. Cost Escalators	B87
	4. Average Historical Aluminum Price	B88
	5. Average Historical Lower Pivot Aluminum Price	B89
	6. Price Deflator Procedures	B89

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1987 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1987. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for two years: PF-87, IP-87, CE-87, CF-87, NR-87, SS-87, NF-87, and RP-87. The VI-87 rate schedule reflects adjustments of and supplements to the rate schedule VI-86 and associated GRSPs (which are to be in effect for 7 years). Sections III.A and VI.J of the VI-87 rate schedule are to be in effect for two years. BPA proposes that rate schedule SI-87 be effective two years, except for the Special Industrial Offpeak rate provision, which is to remain in effect through June 30, 1990, pursuant to an Amendatory Agreement between BPA and Hanna Nickel Smelting Company executed July 1, 1985.

BPA proposes that the SP-87 rate schedule, and the GRSPs associated with this schedule, be effective for 5 years. BPA proposes that the Nonfirm Energy Rate Cap be effective for 12 years. BPA proposes that the SL-87 and the GRSPs associated with this schedule be effective for up to 20 years.

B. General Provisions

These 1987 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1985 rate schedules (which became effective July 1, 1985) to the extent stated in the Availability section of each 1987 rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. All sales of power made under these rate schedules are subject to the following acts as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Northwest Power Act.

SECTION II. TYPES OF BPA SERVICE

A. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers, or for direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.)

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged.

Power purchased under the power rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. New Resource Firm Power

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

1. for any New Large Single Load,

2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and

3. for construction, test and start-up, and station service for facilities owned or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser pursuant to the DSI's power sales contract and subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and

2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

D. Special Industrial Power

Special Industrial Power is electric power which BPA will make continuously available to any DSI that qualifies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI's load which is in excess of the DSI's Operating Demand for Industrial Firm Power or Special Industrial Power.

F. Firm Capacity

Firm Capacity is capacity that BPA assures will be available in the amount(s) and during the period(s) specified in the power sales contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

G. Surplus Firm Power

Surplus Firm Power is firm power (capacity, energy, or capacity and energy) in excess of the amount required to meet BPA's existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy is supplied or made available by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is mostly sold under the Nonfirm Energy rate schedule, NF-87. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-87, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements.

However, Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the purchaser in accordance with the provisions of that schedule and the power

sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. in cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;

2. to provide service when no other type of power is deemed applicable; and

3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

Firm Displacement Power is firm power (capacity, enrgy, or capacity and energy) that BPA makes available to Pacific Northwest utilities for use within the Pacific Northwest. The purchased power will replace the generation from resources that is exported from the Pacific Northwest on a firm basis for a period of at least 3 years. Such power may be restricted pursuant to the Restriction of Deliveries section of the GRSPs (section V.E.).

J. Firm Displacement Power

Firm Displacement Power is firm power (capacity, energy, or capacity and energy) that BPA makes available to Pacific Northwest utilities for use within the Pacific Northwest. The purchased power will replace the generation from resources that isexported from the Pacific Northwest on a firm basis for a period of at least 3 years. Such powermay be restricted pursuant to the Restriction of Deliveries section of the GRSPs (section V.E).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. Billing Factors for Demand

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract.

The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

(1) at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

(1) emergencies or breakdowns on, or maintenance of, the Federal system facilities, and

(2) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) to each system for which scheduled demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be the maximum demand established during a specified period of time either during or prior to the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated,

b. the type of demand to be used in the calculation, and

c. the percentage (if any) of that demand which will be used to calculate the Ratchet Demand.

3. Contract Demand

The Contract Demand shall be the maximum number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term "Contract Energy."

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

5. Computed Average Energy Requirement

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the demand which the purchaser may impose on BPA; and

b. the total amount of energy during a billing month which the DSI is entitled to purchase from BPA.

7. Curtailed Demand

A Curtailed Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of

restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power Rate Schedule at the Standard Industrial Rate. Auxiliary Power sales to DSIs electing to purchase under the Variable Industrial Power Rate Schedule (VI-87) shall be made at the rate determined pursuant to section III of the VI-87 rate schedule. Auxiliary Power sales to DSIs purchasing under the Special Industrial Rate will be made only at the Standard Special Industrial Power Rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special Industrial Power) for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand; or

c. Restricted Demand.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly BPA Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request and BPA may agree to a level of service for the Offpeak Periods other than that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an unauthorized increase.

Any DSI whose Measured Demand, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatthour of unauthorized increase associated with each overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule, the Variable Industrial Power rate schedule, and the Standard Rate under the Special Industrial rate schedule. During the Peak Period the BPA Operating Level may be no greater than the Operating Demand for the billing

month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereinafter defined.

a. Metered Energy

The metered energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the power sales contract, and delivered to a purchaser:

(1) at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. Scheduled Energy

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) for each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy

The Contract Energy shall be the maximum number of kilowatthours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

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

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

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

a. include more than one class of power, or

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

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

2. Outage Credit

To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA's inability to provide full service, provided such adjustment is mandated by the purchaser's power sales

contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are not available by the January billing date. The level of the discount shall be determined from the following ratios:

(1) the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. Low Density Discounts issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

b. Eligibility Criteria

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) the purchaser must serve as an electric utility offering power for resale;

(2) the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) the purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For CY 1987, the average Priority Firm Power rate shall be the average of the PF-85 rate for 9 months and the PF-87 Preference rate for 3 months. For CY 1988, the average Priority Firm Power rate shall be the PF-87 Preference rate.

(4) the purchaser's kilowatthour-to-investment ratio (Ratio 3.a.(1)) must be less than 100;

(5) the purchaser's consumers-per-mile ratio (Ratio 3.a.(2)) must be less than 12; and

(6) the purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 25 but less than 35; or

(b) the consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 15 but less than 25; or

(b) the consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is less than 15; or

(b) the consumers-per-mile ratio is less than 3.

4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.6 mills per kilowatthour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the Low Density Discount, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA Area or District office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA Area or District office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA area and/or district offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred. Irrigation reports to BPA shall include the following monthly information for the reporting period:

(1) utility name and period for which the report is being made;

(2) total irrigation sales and total qualifying irrigation energy sales (in kilowatthours) by month;

(3) total qualifying irrigation sales (in kilowatthours) by month under 400 horsepower, for exchanging utilities;

(4) total utility firm system requirements for other than full requirement customers by month (in kilowatthours);

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatt hours ; and

(6) the Purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bimonthly, or seasonally. If the Purchaser is an exchanging utility, the Purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it choses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Cost Recovery Adjustment Clause

a. Terms and Conditions

The Cost Recovery Adjustment Clause applies to the Priority Firm Power (Exchange and Preference), Industrial Firm Power, Variable Industrial Power, Firm Capacity, and New Resource Firm Power rate schedules.

After September 30, 1988, BPA shall evaluate actual financial performance, by comparing BPA's actual fiscal year 1988 funds from operations (net revenues plus charges not requiring funds), to the fiscal year 1988 funds from operations that rates were designed to achieve. When this evaluation is performed, if actuals differ from planned funds from operations for the evaluation period (fiscal year 1988) as specified herein, BPA shall adjust applicable 1987 wholesale power rate schedules over an adjustment period beginning January 1, 1989, and ending September 30, 1989.

Rate schedules subject to the Cost Recovery Adjustment Clause shall be adjusted only if BPA's actual fiscal year funds from operations are either:

(1) Greater than $80 million above planned funds from operations, or

(2) Greater than $45 million below planned funds from operations.

Any resulting upward rate adjustment shall not be greater than 10.0 percent.

b. Cost Recovery Adjustment Formula

BPA shall determine the variance between actual and planned funds from operations for the evaluation period using the following formula:

$$CRV = AFFO - PFFO$$

where:

CRV = Fiscal year 1988 cost recovery variance (in millions of dollars): total underrecovery (if CRV is negative) or overrecovery (if CRV is positive) of planned funds from operations;

AFFO = Actual fiscal year 1988 funds from operations (in millions of dollars): BPA's reported fiscal year 1988 funds from operations calculated as the sum of net revenues, depreciation, and amortization of conservation and fish & wildlife investment;

PFFO = Planned fiscal year 1988 funds from operations (in millions of dollars); PFFO = $222.530.

c. Application if CRV is Negative

If the absolute value of CRV is greater than $45 million, and if CRV is negative, the percentage increase, rounded to the nearest tenth of a percent, shall be calculated as follows:

(1) If CRU is greater than $28.9 million, then the CRAC% is the lesser of:

(a) $CRAC\% = \left(\frac{28.9}{FR1} + \frac{CRU - 28.9}{FR2}\right) * 100$; or

(b) CRAC% = 10.0 percent.

(2) If CRU is less than or equal to $28.9 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

$$CRAC\% = \frac{CRU}{FR1} * 100.$$

where:

28.9 = 3 percent of FR1.

Three percent is the percentage that IP and VI floor rates exceed their respective margin-based rates. $28.9 million is the revenue increase from PF-87, CF-87, and NR-87 classes for which there would be no corresponding revenue increase from IP-87 and VI-87 classes.

CRAC% = Uniform percentage applied to PF-87 (Exchange and Preference), IP-87, VI-87, CF-87, and NR-87 rate schedules and the irrigation discount.

CRU = Cost Recovery Underrun, in millions of dollars, beyond $45 million: the absolute value of CRV greater than $45 million;

FR1 = the sum of the forecasted revenues from the PF, NR, and CF classes of service subject to the Cost Recovery Adjustment Clause for the adjustment period in millions of dollars. For the period January 1, 1989 through September 30, 1989, FR1 = $964.0 million.

FR1 does not include forecasted revenues from public exchange sales and sales from utilities where average system cost is deemed equal to BPA's PF rate. These two types of sales are subject to the Cost Recovery Adjustment Clause, but significant additional revenues could not be collected from them during the rate period through application of the Cost Recovery Adjustment Clause. IP and VI revenues are excluded because no revenue can be expected from these classes of service when the rate adjustment is less than 3 percent (CRU less than or equal to $28.9 million).

FR2 = the sum of the forecasted revenue for PF, NR, CF, and IP and VI at margin based rates for the period January 1, 1989 through September 30, 1989. FR2 = $1319.5 million.

d. Application if CRV is Positive

If CRV is greater than $80 million, the percentage decrease rounded to the nearest tenth of a percent, unless otherwise specified in a rate schedule, shall be calculated as follows:

$$CRAC\% = \frac{CRO}{FR1} * 100$$

where:

CRAC% = Uniform percentage applied to PF-87 (Exchange and Preference), CF-87, and NR-87 rate schedules and the irrigation discount;

CRO = Cost Recovery Overrun in millions of dollars; the amount that (AFFO-PFFO) is greater than $80 million.

FR1 = the sum of the forecasted revenues from the PF, NR, and CF classes of service subject to the Cost Recovery Adjustment Clause for the adjustment period in millions of dollars. For the period January 1, 1989 through September 30, 1989, FR1 = $964.0 million.

IP and VI revenues are excluded because rates for those customer classes are at the floor and thus receive no adjustment when CRV is positive.

e. Application to Irrigation Discount

In addition to the direct application of the Cost Recovery Adjustment percentage to the irrigation discount, an additional adjustment shall be made so that irrigation loads are not disproportionately affected by a 9-month adjustment period as compared to a 12-month adjustment period. This additional adjustment is reflected in the following formula which represents the total CRAC adjustment to the irrigation discount:

Adjusted Irrigation Discount (in mills per kilowatthour) =

$$4.6 * (1 + \frac{CRAC\%}{100}) + (.046 * CRAC\%)$$

where:

4.6 = Irrigation discount applicable to PF-87 and NR-87, in mills per kilowatthour;

CRAC% = Uniform percentage applied to PF-87 (Exchange and Preference), IP-87, VI-87, CF-87, and NR-87 rate schedules and the irrigation discount.

.046 = Mills per percentage CRAC adjustment; difference between 9 and 12 month CRAC adjustment periods.

f. Cost Recovery Adjustment Clause Implementation Process

(1) Within 30 days of the end of Fiscal Year 1988, BPA shall make an initial calculation to identify the difference between preliminary unaudited AFFO and PFFO.

(2) On or about November 1, 1988, BPA shall notify interested persons and the purchasers under each applicable rate schedule of BPA's initial findings concerning the difference between AFFO and PFFO for the evaluation period.

(a) If no adjustment is required, or if the Administrator waives implementation of an adjustment, BPA shall state in the notice the basis for its decision.

(b) If BPA determines that an adjustment to applicable rates is required, BPA shall state in the notice the amount of the adjustment, the calculation of the adjustment and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA. Such documentation, if nonproprietary and/or nonprivileged, shall be available upon request unless unduly burdensome. The notice shall also contain the tentative schedule for the remainder of the implementation process.

(3) On or about November 4, 1988, BPA shall conduct a public meeting in which interested persons and purchasers under each applicable rate schedule may seek off-the-record clarification of the adjustment amount, calculation, and application to specific rate schedules. For the purpose of further mailings, a list of the names and addresses of interested persons and purchasers (hereafter referred to as "mailing list") shall be compiled at this meeting.

(4) On or about November 8, 1988, purchasers under each applicable rate schedule may submit information requests to BPA regarding the adjustment. The requests shall also be mailed to all persons on the mailing list. BPA shall respond to the requests within 2 working days of their receipt, or as soon as practicable if 2 days is insufficient time within which to respond.

(5) On or about November 15, 1988, interested persons and purchasers under each applicable rate schedule may submit written comments to BPA regarding the

adjustment. The comments shall also be mailed to all persons on the mailing list.

(6) On or about December 1, 1988, commenters may respond to any comments.

(7) On or about December 1, 1988, BPA may release, if available, revised preliminary unaudited AFFO and any resulting revised adjustment to applicable rate schedules.

(8) On or about December 15, 1988, BPA shall conduct an on-the-record public comment forum in which interested persons and purchasers under each applicable rate schedule may present oral comments to BPA.

(9) On or about December 20, 1988, BPA shall notify interested persons and purchasers under each applicable rate schedule of the audited AFFO, the amount of the adjustment, the calculation of the adjustment and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA.

(10) The rate adjustment shall be in effect from January 1, 1989, through September 20, 1989.

6. Coincidental Billing

Purchasers of Priority Firm Power and New Resource Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See the Special Provisions Exhibits of the Power Sales Contract, GCP, E, 17.

7. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF, CF, and NR rate schedules are subject to the Conservation Surcharge. If only a portion of the customer's service area is subject to the

surcharge, then the amount of the surcharge shall equal 10 percent of the total charge for all power purchases multiplied by: (a) the portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sunday. This definition does not apply to the Special Industrial Offpeak Rate.

SECTION IV. OTHER DEFINITIONS

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy

Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

a. All identifiable costs (expressed in mills per kilowatthour) associated with the use of a displaceable thermal resource or end-user load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

b. All identifiable costs (expressed in mills per kilowatthour) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the purchaser.

C. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maxmimum nonfirm energy price for general application. At no time shall the total price for nonfirm energy, including any applicable service charges or rate adjustment, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning from the date the 1987 Wholesale Power Rates and associated GRSPs are made effective on an interim or final basis by the Federal Energy Regulatory Commission (FERC).

2. Monthly Notification of the NF rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3. of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BASC at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF rate Cap by month throughout the period the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + .30(DEC - BASC)

Where

BASC = BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 23.2 mills per kilowatthour.

DEC = The Decremental Fuel Cost as determined in accordance with section IV.C.5. of these GRSPs.

4. Determination of BPA's average system cost

For purposes of determining BPA's average system cost (BASC), the following definition shall apply:

a. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of Decremental Fuel Cost

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. The monthly decremental fuel cost shall be the sum of:

a. the weighted average California price for gas determined by multiplying the gas weighting factor (WGU) developed pursuant to section IV.C.8.a. times the monthly California gas price (MGP) determined pursuant to section IV.C.6. rounded to the nearest tenth of a mill; and

b. the weighted average California price for petroluem determined by multiplying the petroluem weighting (WOU) factor developed pursuant to section IV.C.8.b. times the monthly California petroluem price (MOP) determined pursuant to section IV.C.7. rounded to the nearest tenth of a mill.

6. California Gas Price

The monthly gas price (MGP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MGP = \frac{AGP * HGP}{10}$$

Where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Adminstration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HGP = the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r) using the following procedures:

a. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California gas price in a. above, by the average monthly California gas price in b. above, and rounding to the nearest one-tenth, or three significant places.

10 = the factor for converting gas prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowtthour.

7. California Petroleum Price

The monthly petroleum price (MOP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MOP = \frac{AOP * HOP}{10}$$

Where:

AOP = the last available average oil price for California electric utility plants expressed in cents per million Btu reported in Electric Power Monthly (EPM) published by the Energy Information Adminstration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HOP = the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:

a. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10 = the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowtthour.

8. Weighting Factors

For purposes of determining a California fuel prices for the month, gas and petroleum prices will be weighted based on California's historical use of these two alternative fuels.

a. Historical Gas use in California

The following formula shall be used to determine the weighting factor for gas prices (WGU):

WGU = CGU * HGU

Where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Adminstration (EIA), U.S. Department of Energy.

HGU = the historical relationship between gas consumptions in the effective month of the NF Rate Cap (month t) and the month for which gas consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of gas in California for the month t as determined in (1) above by the average consumption of gas for the

month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum use in California

The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

WOU = COU * HOU

Where:

COU = the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Adminstration (EIA), U.S. Department of Energy.

HOU = the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month t) and the month for which petroleum consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of petroleum in California for the month t as determined in (1) above by the average consumption of petroleum for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of SL Floor Projection and Ceiling Projection

By October 1 of each year, BPA shall determine the present value of the forecasted Priority Firm rate or successor rate(s), BPA's opportunity cost of surplus power, and the cost of BPA's highest cost resource for each fiscal year of the succeeding 21-year period. This determination shall be used to calculate the Floor projection and Ceiling projection for any contract using the SL-87 rate schedule executed during the succeeding 12 months. The Floor projection and Ceiling projection shall be calculated as stated in Section II.A and II.B of Rate Schedule SL-87.

An initial determination of the present value of the Priority Firm rate, BPA's opportunity cost, and the cost of BPA's highest cost resource shall be published on or about August 1 of each year. Within 14 days of the date of BPA's notice, any interested parties shall notify BPA's Office of Public Involvement in writing that they request to be placed on a list of interested parties. The request shall state the name and address of the person, and shall designate no more than two persons on whom service shall be made. Thereafter, communications by and between BPA and interested parties will be limited to those parties appearing on the interested parties list.

Following BPA's notice of its initial determination, BPA shall afford interested parties the opportunity to:

(1) Obtain or be provided reasonable access to nonproprietary and nonprivileged BPA financial data and support relevant to BPA's determination.

(2) Submit written comments to BPA by September 15 regarding the determination. Interested parties shall mail copies of their comments to all parties appearing on the list of interested parties compiled by BPA.

Consideration of comments and more current information may result in a different calculation from that initially proposed. The final determination shall be published on October 1.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF-87, and Emergency Capacity rate schedule, CE-87, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or

2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

B. Construction, Test and Start-Up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period--Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or

b. bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. suspended,

2. interrupted,

3. interfered with,

4. curtailed, or

5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

SECTION VI. BILLING INFORMATION

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose total load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. the NLSL demand during BPA's diurnal capacity billing periods,

2. the NLSL energy during BPA's energy billing periods, and

3. the NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the purchaser's billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.

F. Billing Month

Meters normally will be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately.

The calendar month in which the purchaser's meter is scheduled to be read determines the billing month. (Thus, a bill associated with a meter scheduled to be read on April 10 would be an April bill.) The charges for the winter and summer periods identified in the rate schedules apply to the purchaser's billing months.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as

directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the

purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

As necessary, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the amount of the bill which it is replacing, the additional amount will be billed on a separate bill, and the date of the revised bill shall be its date of issue.

SECTION VII. VARIABLE INDUSTRIAL RATE PARAMETERS AND ADJUSTMENTS

A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price

The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by Metals Week, in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price

BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly

billing aluminum price to be used for billing purposes. Upon written request supporting documentation shall be provided.

3. Changes in Aluminum Price Indicators

In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B of the rate schedule, shall be subject to change for billing purposes as herein described. The term "annual adjustment date" shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1987 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA's revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determinations and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, those parties that submitted comments, and parties that requested notification, of the final determination.

2. Annual Adjustment Procedures

a. Annual Adjustment of the Lower Pivot Aluminum Price

Beginning with the July 1, 1987, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

b. Annual Adjustment of the Upper Pivot Aluminum Price

For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date.

(1) Annual adjustment for the period beginning July 1, 1987, and ending June 30, 1991

The Upper Pivot Aluminum Price shall be revised by multiplying 72 cents per pound by the Cost Escalation Index described in section VII.B.3.c of these GRSPs and rounded to the nearest tenth of a cent. The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

(2) Annual Adjustment for the period beginning July 1, 1991, and ending June 30, 1993

The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the mid-point between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(a) (2)*(AAP) - ALP:

where

AAP = the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.

ALP = the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.

(b) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(c) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. Cost Escalators

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) Electricity Cost Index

The average VI-86 rate in mills per kilowatthour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatthour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 1.115 (the value of the GNP Implicit Price Deflator for 1985 with 1982 = 1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:

Electricity Cost Index	.30
Labor Cost Index	.20
Alumina Cost Index	.20
Other Costs Index	.30

c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:

Electricity Cost Index	.25
Other Costs Index	.75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the Variable rate has been in effect. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the Variable Industrial rate has been in effect shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year's dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred. Each price shall be rounded to the nearest tenth of a cent.

APPENDIX C

TRANSMISSION RATE SCHEDULES

AND

GENERAL TRANSMISSION RATE

SCHEDULE PROVISIONS

TRANSMISSION RATE SCHEDULES
AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

TABLE OF CONTENTS

Transmission Rate Schedules		Page
FPT-87.1	Formula Power Transmission	C1
FPT-87.3	Formula Power Transmission	C3
IR-87	Integration of Resources	C5
IS-87	Southern Intertie Transmission	C7
IN-87	Northern Intertie Transmission	C8
IE-87	Eastern Intertie Transmission	C9
ET-87	Energy Transmission	C10
MT-87	Market Transmission	C11

General Transmission Rate Schedule Provisions		
SECTION I	Adoption of Revised Transmission Rate Schedules and General Transmission Rate Schedule Provisions	C12
SECTION II	Billing Factor Definitions and Billing Adjustments . . .	C12
SECTION III	Other Definitions	C14
SECTION IV	Billing Information	C16

SCHEDULE FPT-87.1

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes schedule FPT-85.1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once a year. It is available for firm transmission of electric power and energy using the Main Grid and/or Secondary System of the FCRTS. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Full-Year Service

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

1. Main Grid Charge

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

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0250 per mile;

b. Main Grid Interconnection Terminal Factor: $0.20;

c. Main Grid Terminal Factor: $0.25;

d. Main Grid Miscellaneous Facilities Factor: $1.04;

2. Secondary System Charge

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

a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.1255 per mile;

b. Secondary System Transformation Factor: $1.95;

c. Secondary System Intermediate Terminal Factor: $0.72;

d. Secondary System Interconnection Terminal Factor: $0.36;

3. Intertie Charge

For use of the Southern Intertie facilities: $5.21.

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A for all months of the year except for agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the monthly charge shall be:

1. during months for which service is specified, the monthly charge defined in Section II.A, and

2. during other months, the monthly charge defined in Section II.A multiplied by 0.2.

SECTION III. BILLING FACTORS

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand;

B. the highest hourly Scheduled Demand for the month; or

C. the Ratchet Demand.

SCHEDULE FPT-87.3

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes schedule FPT-83.3 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 3 years. It is available for firm transmission of electric power and energy using the Main Grid and/or Secondary System of the FCRTS. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Full-Year Service

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

1. Main Grid Charge

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

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0250 per mile;

b. Main Grid Interconnection Terminal Factor: $0.20;

c. Main Grid Terminal Factor: $0.25;

d. Main Grid Miscellaneous Facilities Factor: $1.04;

2. Secondary System Charge

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

a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.1255 per mile;

b. Secondary System Transformation Factor: $1.95;

c. Secondary System Intermediate Terminal Factor: $0.72;

d. Secondary System Interconnection Terminal Factor: $0.36;

3. Intertie Charge

For use of the Southern Intertie facilities: $5.21.

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A for all months of the year except for agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

1. during months for which service is specified, the monthly charge defined in Section II.A, and

2. during other months, the monthly charge defined in Section II.A multiplied by 0.2.

SECTION III. BILLING FACTORS

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand;

B. the highest hourly Scheduled Demand for the month; or

C. the Ratchet Demand.

SCHEDULE IR-87

INTEGRATION OF RESOURCES

SECTION I. AVAILABILITY

This schedule supersedes IR-85 and is available for firm transmission service for electric power and energy using the Main Grid and/or Secondary System of the FCRTS. The definitions of Main Grid and Secondary Systems are the same as for the FPT-87.1 and FPT-87.3 rate schedules and are contained in the General Transmission Rate Schedule Provisions. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The monthly charge shall be the sum of A and B where:

A. The Demand Charge shall be:

1. $0.2600 per kilowatt of billing demand; or

2. for Points of Integration (POI) specified in the Agreement as being short distance POI's, for which Main Grid and Secondary System facilities are used for a distance of less than 75 circuit miles, the following formula applies:

[0.2 + (0.8/75 x transmission distance)] ($0.2600 per kilowatt of billing demand)

Where:

the billing demand for a short distance POI is the demand level specified in the Agreement for such POI, and the transmission distance is the circuit miles between the POI for a generating resource of the customer and a designated Point of Delivery (POD) serving the load of the customer. Short distance POI's are determined by BPA after considering factors in addition to transmission distance.

B. The Energy Charge shall be:

0.85 mills/kWh of billing energy.

SECTION III. BILLING FACTORS

To the extent that the Agreement provides for the customer to be billed for transmission in excess of the Transmission Demand or Total Transmission

Demand, as defined in the Agreement, at the nonfirm transmission rate (currently ET-87), such transmission service shall not contribute to either the Billing Demand or the Billing Energy for the IR rate provided that the customer requests such treatmment and BPA approves in accordance with the prescribed provisions in the Agreement.

A. Billing Demand

The billing demand shall be the largest of:

1. the Transmission Demand, except under General Transmission Agreements where a Total Transmission Demand is defined;

2. the highest hourly Scheduled Demand for the month; or

3. the Ratchet Demand.

B. Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

SCHEDULE IS-87

SOUTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes IS-85 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Nonfirm Rate

The charge for nonfirm transmission of non-BPA power shall be 1.4 mills/kWh of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. Firm Power Transmission Rate

The charge for firm transmission service granted access by BPA shall be $.360 per kW per month of billing demand and .69 mills/kWh of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Power Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced prorata by BPA due to forced Intertie outages, and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SCHEDULE IN-87

NORTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes IN-85 and is available for all transmission on the Northern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for transmission of non-BPA power on the Northern Intertie shall be 1.05 mills/kWh.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of the scheduled kilowatthours.

SCHEDULE IE-87

EASTERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes IE-85 and is available for all nonfirm transmission on the Eastern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for transmission of nonfirm energy on the Eastern Intertie shall be 2.08 mills/kWh.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of the scheduled kilowatthours.

SCHEDULE ET-87

ENERGY TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes Schedule ET-85, unless otherwise specified in the Agreement, with respect to delivery using FCRTS facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie, and is available for nonfirm transmission between points within the Pacific Northwest. BPA may interrupt service which is provided under this rate schedule. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for such nonfirm transmission of non-Federal electric energy shall be 1.61 mills/kWh.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

SCHEDULE MT-87

MARKET TRANSMISSION

SECTION I. AVAILABILITY

This schedule is available for Transmission Service for transactions using FCRTS facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge shall be determined in advance by BPA. The charge shall not exceed 33 percent of the difference between the highest Decremental Cost of generation of the WSPP and the lowest Decremental Cost of generation of the WSPP as determined by the WSPP Operating Committee during the year prior to the effective date of the WSPP Agreement. The Operating Committee may determine that a subsequent redetermination is necessary based upon the immediately preceeding year's experience. However, the transmission charge shall not be less than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing factors shall be specified in advance by BPA, as to representing the Transmission Service use or reservation.

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

A. Approval of Rates

These rate schedules and General Transmission Rate Schedule Provisions (GTRSP) shall become effective upon approval by the Federal Energy Regulatory Commission. BPA will request FERC approval effective October 1, 1987. BPA is requesting that all proposed Transmission Rate Schedules be effective for a period of 2 years, from October 1, 1987, through September 30, 1989, with the exception of the FPT 87.3 rate schedule, which is effective for a period of 3 years, through September 30, 1990.

B. General Provisions

These 1987 Transmission Rate Schedules and associated GTRSP supersede in their entirety BPA's 1985 Transmission Rate Schedules and GTRSP (which became effective July 1, 1985) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission Service provided shall be subject the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

The Metered Demand in kilowatts shall be largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

The demand as defined in the Agreement.

4. Total Transmission Demand

The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Decremental Cost

As used in the MT rate schedule, Decremental Cost is as defined in the WSPP Agreement.

C. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

D. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

E. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

F. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network in the Wholesale Power Rate Development Study used in BPA's rate development.

G. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

H. Main Grid Distance

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

I. Main Grid Interconnection Terminal

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

J. Main Grid Miscellaneous Facilities

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

K. Main Grid Terminal

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

L. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

M. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary substation to the United States-Canadian border, and the associated substation facilities.

N. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

O. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

P. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

Q. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI or the Main Grid and the POD or the lower voltage FCRTS facilities which may be used on a use-of-facility basis.

R. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

S. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

T. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

U. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the Oregon-California border, a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation, and one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

V. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the WSPP Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

At its option, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the amount of the bill which it is replacing, the date of the revised bill shall be its date of issue.

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